TransGlobe Energy Corporation

2004

Annual Report

CONTENTS

Annual Meeting

TransGlobe Energy Corporation will hold its Annual Meeting on Wednesday, May 11, 2005 at 3:00 p.m. The meeting will be held in the Viking Room at the Calgary Petroleum Club located at 319 - 5th Avenue S.W., Calgary, Alberta, Canada.

This annual report may include certain statements that may be deemed to be "forward-looking statements" within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. All statements in this annual report, other than statements of historical facts, that address future production, reserve potential, exploration drilling, exploitation activities and events or developments that the Company expects, are forward-looking statements. Although TransGlobe believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. Factors that could cause actual results to differ materially from those in forward-looking statements include, but are not limited to, oil and gas prices, exploitation and exploration successes, continued availability of capital and financing, and general economic, market or business conditions.

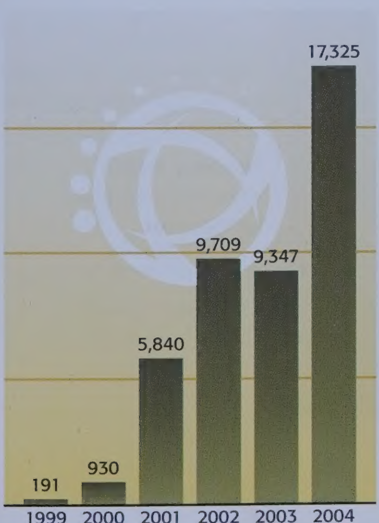
Highlights

- ***Record Production averaged 3,796 Boepd in 2004, increased 44% over 2003.***
- ***Record Cash flow of $17.3 million in 2004, increased 85% over 2003.***
- ***Proved Plus Probable reserves of 10.4 million increased 48% over 2003.***
- ***Record drilling program, 28 wells (14 oil, 10 gas and 4 D&A), 86% success.***
- ***2nd Yemen project, Block S-1, commenced production.***
- ***3rd Yemen project, Block 72, acquired.***
- ***Egypt Nuqra Block farmin, new country and operatorship.***
- ***Continued growth in Canada, production increased 158% over 2003.***
- ***December 31 working capital of $2,839,000 with no debt.***

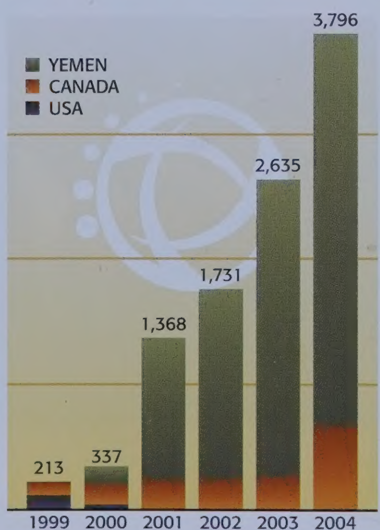
Throughout the text of TransGlobe's annual report and consolidated financial statements, all dollar values are expressed in United States dollars unless otherwise stated.

Disclosure provided herein in respect of Boe's may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

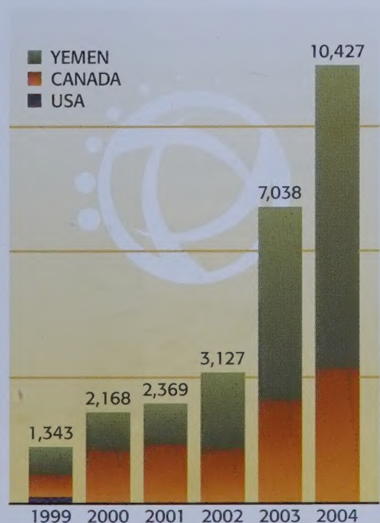
Cash Flow
(000 US $)



Production
(Boed)



Proved Plus Probable Reserves
(MBoe)



Message To The Shareholders

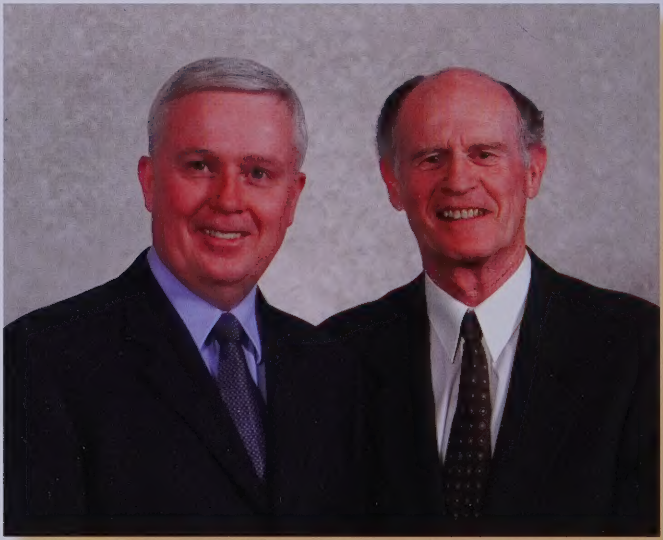
I am pleased to submit the 2004 Annual Report to the shareholders. TransGlobe enters 2005 as a much larger and stronger company with all of the elements in place to ensure continued growth. Larger, because compared to a year ago, land holdings have increased 18 fold and reserves are 48% higher; stronger because, production rates are 44% higher and world oil prices are at record highs. The higher production rates and high world oil prices are expected to provide sufficient cash flow to fund our 2005 capital budget.

In 2004 TransGlobe management implemented two strategies for growth internationally: accelerated development work and sourcing new exploration acreage.

The 2004 Yemen drilling program consisted of 12 development wells (all oil wells) and one exploration well (dry). A production system was installed on the An Nagyah field and oil production commenced in March 2004, trucking oil to the Hunt pipeline. Early production capitalized on high oil prices, provided additional cash flow during a period of high development expenditures, and gave insight into the production performance of the Lam reservoir. Based on the production performance to date, we are hopeful that An Nagyah will outperform our initial expectations for the field, much as Tasour performance has exceeded expectations.

The second component of the growth strategy was to increase international exploration acreage including the addition of a new operated project. Candidate projects were subjected to a highly selective screening process which required high prospectivity, lightly explored acreage, good fiscal terms and (for one project) TransGlobe operatorship. I am very encouraged by the quality of the two new project areas added during 2004.

The first project, Block 72 in the Masila basin of Yemen, was won in a bidding round in June 2004 in partnership with the other Block 32 partners. Block 72 is located to the southwest of Block 32, in an area where we understand the geology and operations. The prospects identified to date are similar to Tasour. A discovery could be developed in the same timeframe and format as the Tasour field on Block 32.



Ross G. Clarkson
President, CEO
and Director

Robert A. Halpin
Chairman of the Board
and Director

The second project acquired in 2004 is the Nuqra Block in Egypt. This project is a major step for the Company: it is our first operated project internationally; it is a new focus country. The Nuqra Block has the indicators for a prolific oil basin: oil shows on surface and in an exploration well, source rock, reservoirs, suitable structures. It will take several years to evaluate, due to the size of the Block and due to limited seismic data and well information. TransGlobe plans an aggressive exploration program on the Nuqra Block and expects to acquire new seismic in 2005 in preparation for drilling in late 2006.

The Year Ahead

To maintain our high growth rate we must find new reserves. Therefore the next two years will see a much greater focus on exploration drilling. The two new exploration projects provide a larger opportunity base. New seismic acquisition on Block 32, Block 72 and the Nuqra Block and reprocessing of existing seismic on Block S-1 will take a greater portion of TransGlobe's budget. Eight to ten "wildcat" exploration wells will be drilled in 2005 and probably an even higher number in 2006. To lower exploration risk we have selected each of our projects carefully. They are all located in oil prone basins where there are multiple drillable structures with several prospective horizons. TransGlobe utilizes state of the art exploration techniques to minimize exploration risk, however exploration drilling is higher risk than the program carried out in 2004. The potential reward is significant in that success in a single exploration well, on any one of our project areas, will enable TransGlobe to maintain its high rate of growth in production and cash flow.

Development work will continue into 2005, culminating with the startup of the pipeline and facilities on the An Nagyah field. An Nagyah is only the beginning of Block S-1 development. Unlocking the potential of the Harmel shallow oil, or the An Naeem gas/condensate are near term development opportunities that could increase production.

Just as the Tasour field on Block 32 funded TransGlobe's exploration and development of Block S-1, An Nagyah development will provide cash flow for the Company to expand exploration on Blocks S-1, 32, 72 and Nuqra. When the pipeline and production facility becomes fully operational in mid 2005, revenues will increase dramatically, leading to an expanded exploration budget for 2005 and 2006.

In Canada, our 2005 program will be development oriented, following a period of exploration in 2004 which resulted in new discoveries at Gadsby, Three Hills and Thorsby. We will also proceed with development work on the Nevis and Twining gas pools. Canadian exploration provides balance and diversification to our international ventures and has proven to be an excellent investment.

Our producing properties in Yemen and Canada provide a solid foundation of financial strength to pursue international exploration. High reward international projects take money, time, expertise and perseverance. Our team has a proven record and a dedication that verges on obsession. Every exploration block was chosen with a vision of its potential. We are inspired by the quality of the opportunities and are implementing an aggressive exploration program.

Ross G. Clarkson
President, CEO and Director

March 15, 2005

Operations Review

INTERNATIONAL ACTIVITY

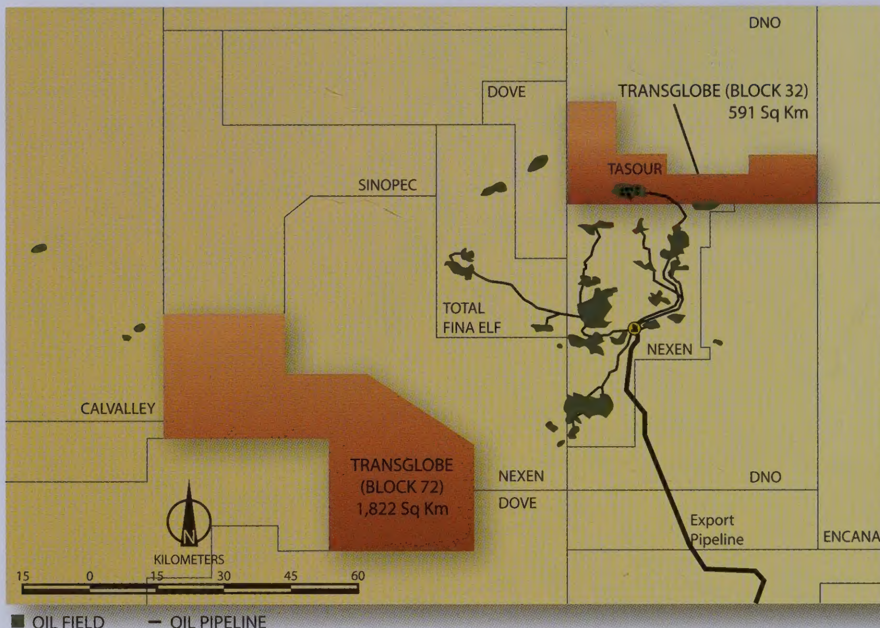
BLOCK 32, REPUBLIC OF YEMEN

- Three development oil wells drilled in 2004, 100% success.
- Appraisal of Tasour West extension.
- 3-D Seismic shot over the greater Tasour area (100 square km).
- Proved plus probable reserves increased 32% replacing 186% of 2004 production.

Background

TransGlobe entered into its first international project in January 1997 through a farmout agreement and joint venture on Block 32. The Company has since participated in acquisition of seismic data, drilling of twenty wells and construction of production facilities. The Tasour field commenced production on November 3, 2000. The joint venture currently consists of TG Holdings Yemen Inc. (a wholly-owned subsidiary of TransGlobe Energy Corporation) with a 13.81087% working interest and partners Ansan Wikfs Hadramaut Ltd. and DNO ASA holding the balance ("the Block 32 Joint Venture Group"). DNO ASA (an independent Norwegian oil company) is the operator of the Block. The Yemen Oil Company ("YOC" - a Yemen government oil company) has a 5% interest in the Block 32 Joint Venture Group's production sharing oil.

The Block 32 development area covers 591 square kilometers (146,070 acres). The development area encompasses all of the Tasour structure and several additional prospects. The approved development/production period extends until the year 2020, with an optional five-year extension to 2025.



2004 Activities and Results

Exploration/Development

During 2004, the Block 32 Joint Venture work program consisted of the acquisition of a 100 square kilometer 3-D seismic program over the greater Tasour area and the drilling of three development wells in the western extension of the Tasour field. The well results are summarized in the table below.

2004 Drilling Results

Well	Date Completed	Initial Production Test (Bopd - gross)	Formation
Tasour #12	June 2004	6,100	Qishn sandstone
Tasour #13	September 2004	2,240	Qishn sandstone
Tasour #14	October 2004	2,820	Qishn sandstone

Production

The Tasour field continues to be a stellar performer, averaging 17,760 Bopd (2,453 Bopd to TransGlobe) during 2004. During 2004, the primary focus on Block 32 was the development of the western extension of the Tasour field, with additional work to increase water disposal capacity. As is typical of all the Qishn fields in the prolific Masila basin, the economic success of the project is dependent upon handling increased water production in a cost effective manner. The strong natural water drive provides an exceptional primary recovery (over 50% of the original oil in place). All the Qishn wells in Tasour and in the Masila basin are pumped utilizing very large electric (up to 1,000 hp) submersible pumps. The power in the Tasour field is generated by diesel powered generators, making diesel costs one of the largest components of operating costs. In late 2004, the Joint Venture group approved the purchase of a diesel topping plant which is

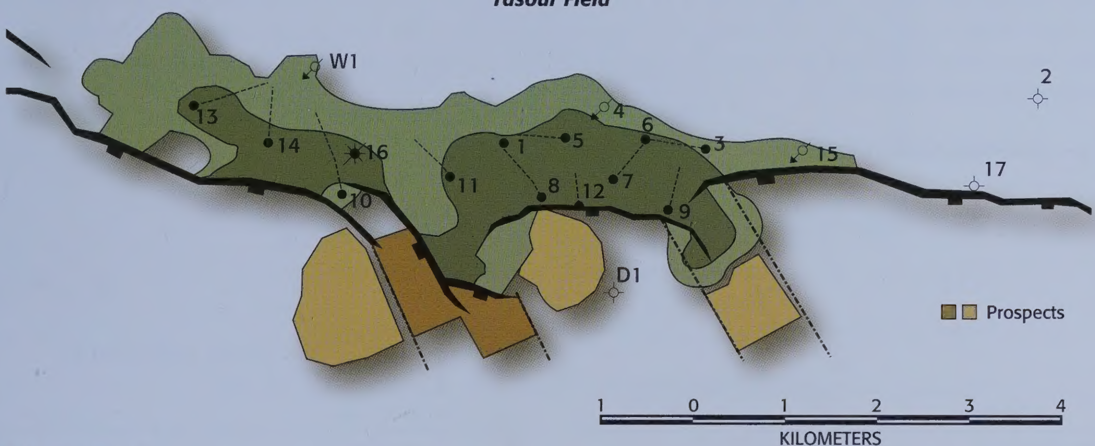
expected to be operational during the third quarter of 2005. The diesel topping plant will produce diesel fuel from a portion of the Tasour crude oil. This is expected to stabilize diesel costs and maintain low operating costs which should extend the life of the field.

2004 Tasour Production by Quarter (Bopd)

	Q-1	Q-2	Q-3	Q-4
Gross field production rate	16,581	16,929	18,464	19,050
TransGlobe working interest	2,290	2,338	2,550	2,631
TransGlobe net (after royalties)	1,660	1,270	1,378	1,367
TransGlobe net (after royalties and tax)	1,465	911	981	941

Under the terms of the Block 32 production sharing agreement ("PSA") royalties and taxes are paid out of the government's share of production sharing oil.

Tasour Field



2005 Outlook

The main Tasour field is now largely developed. Therefore the primary focus for 2005 will be exploration for new reserves. The Block 32 Joint Venture group initially approved a 6 well drilling program for 2005 and recently discussed expanding the 2005 program to 8 wells by utilizing a second drilling rig. A new 70 km 2-D seismic program is planned for early 2005 to define several interesting exploration leads located north and west of the Tasour area.

In the first quarter of 2005 the group drilled Tasour #15, #16 and #17 on Block 32. Tasour #15 was drilled as a water injector near the central production facility ("CPF") and found a 2.5 meter oil column. The well was completed as a water injection well. Tasour #16 was suspended after encountering 6.0 meters of oil pay overlying 3.0 meters of water bearing sandstone. The dip meter indicates a structurally higher location can be reached by sidetracking the well to the south of the current bottom hole location. The Tasour #17 well was drilled approximately 2.0 kilometers east of Tasour #15 to test a new structure east of the Tasour field. The well has been plugged and suspended after encountering Qishn S-1A sand in a structurally low position. Although hydrocarbon shows were encountered, no tests were conducted as it was determined that the Qishn S-1A sand was water bearing.

Two development wells are planned for the main Tasour field and a deep exploration well is planned to test formations below the producing Tasour Qishn formation on a prospect defined on the 3-D seismic survey. In addition several new Qishn prospects have been identified and one or two are expected to be drilled in 2005.

BLOCK 72, REPUBLIC OF YEMEN

In June 2004 the Ministry of Oil and Minerals ("MOM") selected the joint venture group comprised of DNO ASA (34%), TG Holdings Yemen Inc. (33%) and Ansan Wikfs (Hadramaut) Limited (33%) ("Block 72 Partnership") as the successful bidder for Block 72 in the International Bid Round for Exploration and Production of Hydrocarbons. TG Holdings Yemen Inc. is a wholly owned subsidiary of TransGlobe Energy Corporation. Block 72 encompasses 1,822 square kilometers (approximately 450,234 acres) and is located in the western Masila Basin adjacent to the Canadian Nexen Masila Block. The bid consists of an exploration work program and a signature bonus of $1.05 million ($350,000 to TransGlobe). The work program is split into two, thirty month exploration periods and entails seismic acquisition and two wells in each period.

2005 Outlook

The Block 72 Production Sharing Contract has been approved by the Cabinet and as of early March 2005 it is before the Yemen Parliament for final approval. Following approval, the Block 72 Partnership plans to reprocess existing seismic and to acquire new 3-D seismic to identify drilling locations. Drilling is anticipated to commence late in 2005 or early 2006. Any discoveries made on Block 72 would follow a similar development program to Block 32's whereby a separate oil processing facility would be constructed and a pipeline would connect to the Nexen export pipeline.

BLOCK S-1, REPUBLIC OF YEMEN

- 10 wells drilled (9 appraisal/development oil wells and 1 exploration dry well), 90% success.
- Early production of An Nagyah field commenced late March utilizing trucks.
- Field production averaged 2,664 Bopd (666 Bopd to TransGlobe) during 2004.
- Proved plus probable reserves increased to 4.0 million barrels, an 84% increase over 2003.

Background

TransGlobe entered into its second international exploration venture in 1997 by signing a Production Sharing Agreement ("PSA") for the Damis S-1 Block ("Block S-1") with the MOM. TG Holdings Yemen Inc. (a wholly owned subsidiary of TransGlobe Energy Corporation) entered into a joint venture arrangement for Block S-1 with a subsidiary of Vintage Petroleum Inc., a U.S. independent exploration and production company ("Block S-1 Joint Venture Group"). During 2000 Vintage earned a 75% working interest in Block S-1 by funding 100% of the work commitments for the first exploration period of the Block S-1 PSA and by spending a minimum of $20 million. TransGlobe has retained a 25% working interest in Block S-1. Vintage is the operator of Block S-1. The YOC has a 17.5% interest in the Block S-1 Joint Venture Group's share of production sharing oil.

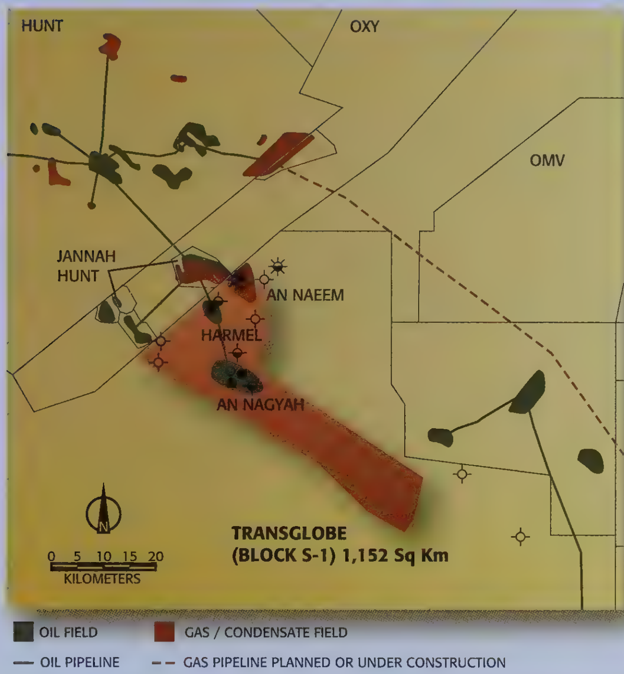
Block S-1 originally encompassed an area of 4,484 square kilometers (approximately 1.1 million acres). Upon declaring commerciality in October 2003, a final relinquishment reduced the Block to a Development Area of 1,152 square kilometers (284,700 acres). The Development Area is now valid until October 2023 with an additional five year extension available.

To year end 2004, the Company has participated in two 3-D seismic surveys, drilling of 19 wells and the construction of early production facilities, resulting in the commencement of production in late March 2004.

2004 Activities and Results

Exploration/Development

During 2004 the primary focus of the Joint Venture Group was the delineation and development of the An Nagyah Lam A oil pool. Eight oil wells were drilled in the An Nagyah Lam A pool (now producing), one appraisal well was drilled at Harmel #2 and one exploration well was drilled at Al Hareth #1 (dry).



2004 Drilling Results

Well	Date Completed	Initial Production Test (Bopd - gross)	Formation
An Nagyah #5	March 2004	1,150	Lam A
An Nagyah #6	April 2004	1,142	Lam A
An Nagyah #7	May 2004	360	Lam A
An Nagyah #8	July 2004	607	Lam A
An Nagyah #9	August 2004	530	Lam A
An Nagyah #10	September 2004	1,547	Lam A
An Nagyah #11 Hz	October 2004	3,100	Lam A
An Nagyah #12 Hz	November 2004	4,801	Lam A
Harmel #2	June 2004	Cased oil, testing 2005	Azal, Sarr, Qishn
Al Hareth #1	August 2004	Dry	Alif Prospect

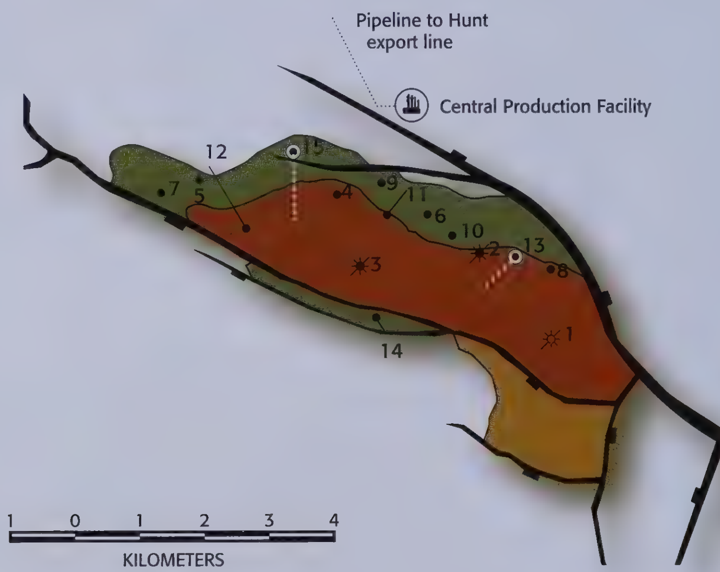
The 2004 drilling program focused on the appraisal and development of the An Nagyah Lam A light oil pool resulting in eight successful producing oil wells during the year. The initial wells were drilled vertically to delineate the pool as mapped on 3-D seismic, with An Nagyah #7 and An Nagyah #8 defining the western and eastern edges of the field respectively. One of the more significant wells drilled during the year was An Nagyah #11, drilled horizontally to improve well productivity and pool drainage. An Nagyah #11 was a relatively short horizontal of approximately 150 meters. The 3,100 Bopd tested from An Nagyah #11 supported a second horizontal well at An Nagyah #12 with a larger horizontal section of approximately 860 meters. The An Nagyah #12 well flow tested 4,801 Bopd while significantly constrained by the 2 7/8 inch tubing in the well. The An Nagyah #12 well confirmed that horizontal drilling is the preferred method to develop the Lam formation.

A workover rig was mobilized in the fourth quarter. The An Nagyah #2 well was successfully re-completed as a producing Lam A oil well. The workover rig also re-completed the An Nagyah #3 well as a Lam A gas injector. Natural gas from the An Nagyah pool is injected into An Nagyah #3 to conserve the gas and to maintain reservoir pressure thereby enhancing oil recovery.

Harmel #2 was drilled in June 2004 to appraise the shallow oil reservoirs found in the discovery well, Harmel #1. The Harmel #2 well is located 1.2 kilometers from the Harmel #1 discovery well. Full diameter cores were cut over three separate oil zones. The analysis of the cores suggested that the well productivity could be improved by acidizing the oil zones. The Harmel #2 well was completed and acidized in November of 2004.

The only exploration well drilled in 2004, Al Hareth #1 was drilled to a total depth of 1,400 meters (4,239 feet) and was abandoned. The primary target, the Alif reservoir sandstone was encountered, however the open hole well logs did not indicate commercial hydrocarbons were present.

An Nagyah Field



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Production

Early production (trucking) facilities were installed at An Nagyah during the first quarter of 2004 with an initial capacity of 2,500 Bopd (625 Bopd to TransGlobe). The oil production is currently being trucked 18 miles to the Jannah Hunt facility where it enters the pipeline to the Ras Isa loading terminal on the Red Sea. Trucking operations will be phased out following the construction of a CPF at An Nagyah and a 28 kilometer (18 mile) pipeline to the Jannah Hunt export pipeline.

After commencing production the trucking facilities were steadily expanded to the current capacity of approximately 7,600 Bopd (1,900 Bopd to TransGlobe). After drilling An Nagyah #12 the field productive well capacity is in excess 12,000 Bopd.

The pipeline and facility construction for the An Nagyah field is on schedule with a planned start up in June 2005. The An Nagyah field production is anticipated to increase to over 10,000 Bopd (2,500 Bopd to TransGlobe) when the facilities and pipeline are operational. The CPF is designed for an initial capacity of 10,000 to 12,000 Bopd (2,500 to 3,000 Bopd to TransGlobe), with expansion capabilities. The 10 inch pipeline has an ultimate design capacity of 80,000 Bopd to provide expansion capabilities for future developments.

2004 An Nagyah Production by Quarter (Bopd)

	Q-1	Q-2	Q-3	Q-4
Gross field production rate	18	2,258	3,626	5,793
TransGlobe working interest	5	565	907	1,448
TransGlobe net (after royalties)	3	393	631	1,008
TransGlobe net (after royalties and tax)	3	352	564	901

2005 Outlook

The focus in 2005 includes the evaluation/assessment of undeveloped discoveries (Harmel and An Naeem), new exploration on the Block, and development drilling on An Nagyah.

Two wells were drilled in the first quarter of 2005 (An Nagyah #14 and Malaki #1). The An Nagyah #14 well was drilled to a total depth of 1,365 meters and suspended as a Lam B oil well in early January 2005. The An Nagyah #14 well encountered a 19 meter oil column in the Lam B (lower Lam) sandstone. The well was swab tested at a rate of approximately 80 barrels of light (40 degree API) oil per day. No water was produced during the test period. This discovery is located south of the An Nagyah field in a separate fault block. The An Nagyah #14 oil test has identified a new exploration fairway south of the main An Nagyah field. Additional work will be required to incorporate the well results and remap the seismic in this area to identify future drilling locations.

Malaki #1 is located approximately nine kilometers south east of the An Nagyah pool. The Malaki #1 exploration well was drilled to a total depth of 2,315 meters. The well was plugged and abandoned after encountering minor hydrocarbon shows. The Lam A sandstone reservoirs were encountered structurally lower than the oil/water contact in the An Nagyah field and were water saturated.

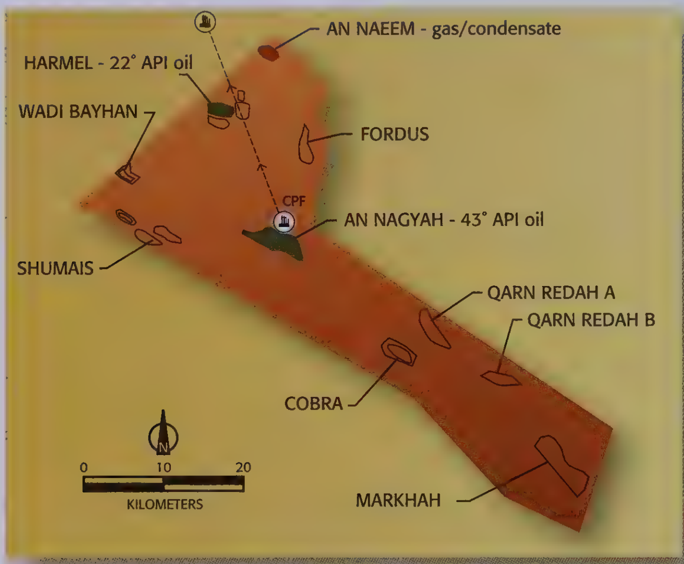
In March 2005 An Nagyah #15 commenced drilling. The An Nagyah #15 well is planned as an 800 meter horizontal well in the northwest area of the An Nagyah field, adjacent to An Nagyah #12. Following An Nagyah #15, it is expected that the drilling rig will move to the Markhah exploration prospect (approximately 40 kilometers south east of An Nagyah).

The An Naeem gas condensate pool is being evaluated for potential make up gas to maintain reservoir pressure and improve recoveries from the An Nagyah pool. Produced condensate could be sold with the An Nagyah crude oil production. A gas cycling scheme to recover condensate from An Naeem is also being studied.

In addition to An Nagyah Lam A development wells (horizontal), it is expected that a Lam B horizontal well will be drilled to develop the Lam B oil pool tested in the An Nagyah #3 and An Nagyah #14 wells, along with several additional exploration wells. The 3-D seismic survey shot in 1999 in the An Naeem area is being reprocessed to further refine additional exploration targets for the 2005/2006 drilling program.

The Harmel #1 and #2 wells are currently being equipped with pumps and production testing equipment which are expected to be operational by the end of the March 2005. It is expected that both Harmel wells will be production tested for three to six months. Production and test data obtained from the Harmel #1 and #2 wells will help to determine the commerciality of the medium gravity oil (22 degree API). The Harmel structure identified on 3-D seismic could require 80 to 90 shallow wells (700 to 800 meters in depth) to be fully developed.

The map below shows the numerous structures identified on Block S-1. It will take several years to fully evaluate the true potential of the large development area.



CPF - Central Production Facility --- Pipeline

NUQRA BLOCK 1, ARAB REPUBLIC OF EGYPT

- Farm out agreement signed for Nuqra Block (7,500,000 acres) in the Upper Nile region.
- Mitchell Wren appointed General Manager and office established in Cairo.
- TransGlobe Egypt assignment of 50% interest and appointment as operator approved in October.
- Commenced seismic reprocessing and geological field work.
- Bid preparation for new seismic acquisition planned for fourth Quarter 2005.

Background

In July 2004, TransGlobe Petroleum Egypt Inc. ("TransGlobe Egypt"), a wholly owned subsidiary of TransGlobe Energy Corporation, entered into a Farmout Agreement with Quadra Egypt Limited ("QEL"), a subsidiary of Quadra Resources Corp. headquartered in Calgary, and Rampex Petroleum International ("Rampex") headquartered in Cairo, Egypt. This agreement provides TransGlobe Egypt the opportunity to participate and earn a 50% working interest in the Nuqra Concession.

Under the terms of this agreement TransGlobe Egypt will earn 50% of the Nuqra Concession by paying 100% of the initial $6.0 million of qualifying expenditures in the Stage 1 and the Stage 2 work programs. QEL will hold a 30% working interest in the Concession and Rampex will hold a 20% working interest. After the initial earning, costs will be shared 60% TransGlobe Egypt, 40% QEL and Rampex will be carried until first production. The cost of the Rampex carry will be recovered by TransGlobe Egypt and QEL from 100% of the Rampex cost oil and 50% of the Rampex production sharing oil. TransGlobe Egypt is the Operator of the Nuqra Block.

The Nuqra Concession Agreement Stage 1 work program requires expenditure of $2.0 million to reprocess existing seismic and to shoot new seismic within the first two years. Upon expiry of the Stage 1 term, there is an option to proceed to the Stage 2 work program. Stage 2 requires completion of a two well drilling program, with a minimum expenditure of $4.0 million over a period of three years. Upon expiry of the Stage 2 term there is an option to proceed to the Stage 3 work program. Stage 3 requires completion of a two well drilling program, with a minimum expenditure of $5.0 million over a final three year term. Exploitation of discovered commercial fields will continue under a Development Lease for a further 20 years. The Concession fiscal terms allow for the recovery of costs from 40% of production. The remaining balance of 60% of production is then shared on a 70:30 basis between the government and the contractor respectively. Production sharing above 25,000 Bopd is shared on an 80:20 basis.

The Nuqra Concession is located in Upper Egypt near of the city of Luxor on the east bank of the Nile River. The concession encompasses over two-thirds of the Kom Ombo Basin, a rift basin analogous to the Gulf of Suez Basin in Egypt, the Marib Basin in the Republic of Yemen, and the Muglad Basin in Sudan, all of which contain major reserves. The Nuqra Concession contains more than 30,000 square kilometers or 7,500,000 acres of exploration lands with 13 seismically defined leads identified from over 4,000 km of existing 2-D seismic. Seismic and well data have confirmed the existence of Jurassic and Cretaceous sediments and the presence of a petroleum system which could potentially hold significant oil reserves.

2004 Activities

In October 2004 Mr. Mitchell Wren joined the Company as General Manager of TransGlobe Petroleum Egypt Inc. in Cairo. TransGlobe Petroleum Egypt Inc. was assigned a 50% interest in the project and approved as operator by the Egyptian Government in October 2004. An office has been established in Cairo and work has commenced on geological field studies, re-processing of existing 2-D seismic and field acquisition bid parameters for the acquisition of additional 2-D seismic data.

2005 Outlook

TransGlobe has obtained the existing seismic data on the Nuqra Block and is currently re-processing the data to improve the resolution. A new seismic acquisition program is anticipated to commence in the fourth quarter 2005. A field geological survey is also underway to investigate surface outcrops and oil seeps in the Nuqra area. The exploration of the Nuqra Block is being fast tracked and will probably exceed the PSA requirements. It is anticipated that TransGlobe will complete the seismic acquisition by the first quarter of 2006 and will be preparing for a two well drilling program in late 2006. This would complete all the first period and second period PSA commitments ahead of schedule.

CANADA

- Fifteen wells drilled (10 gas, 2 oil, 3 dry), 80% success.
- Production averaged 677 Boepd in 2004, up 158% over 2003.
- Proved plus probable reserves increased 32%, replaced 414% of 2004 production.

Background

TransGlobe acquired its Canadian operations in April 1999. TransGlobe operates most of the wells which are almost entirely in the southern/central part of the Province of Alberta. Until 2003, investment in Canadian operations was limited to development and exploitation of producing areas with minimal investment in land or exploration opportunities. In 2003 and 2004 Canadian operations were successfully expanded providing increased cash flow and asset value. Canadian operations will continue to be expanded to capitalize on the North American gas market.

2004 Activities and Results

Exploration/Development

For the year 2004, the Company drilled 15 wells (11.2 net) resulting in 10 gas wells, 2 oil wells and 3 dry holes for an 80% success rate. The wells were all drilled in central Alberta focusing in the core areas of Nevis (5 gas, 1 oil) and Twining (2 gas). The balance of the wells were drilled at Morningside (oil), Gadsby (gas), Three Hills Creek (gas), Thorsby (gas), with dry holes at Lone Pine Creek and Cynthia. Seven of the 2004 wells were placed on production by year end contributing approximately 350 Boepd in December. Subsequent to year end, two (0.9 net) additional wells (50 Boepd) were tied in and placed on production. Negotiations are currently underway to tie in two (1.5 net) additional wells in 2005 which should contribute an additional 70 Boepd. One Nevis well will undergo additional testing and evaluation prior to initiating tie in negotiations.

Production

Production in the fourth quarter averaged 900 Boepd. Production would have been approximately 1,050 Boepd except for natural gas compression capacity limitations at third party operated facilities in the Nevis and Twining areas (approximately 150 Boepd for the quarter). It is anticipated that additional compression will be installed by mid 2005.

2004 Canadian Production by Quarter (Boepd)

	Q-1	Q-2	Q-3	Q-4
TransGlobe working interest	470	486	846	900
TransGlobe net (after royalties)	392	400	704	748

2005 Outlook

The Canadian 2005 drilling program is expected to commence in April or May after spring break-up to take advantage of lower equipment and service prices during the summer months. The Company plans to drill 10 to 15 wells in Canada during 2005. The majority of the wells will be drilled in the Nevis area, targeting natural gas.

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CONSOLIDATED PRODUCTION

The following table is a summary of working interest production, **before royalty**, by country, for the years ended 2004 and 2003:

	2004			2003		
	Oil & Liquids Bopd	**Gas Mcfpd**	**Total Boepd**	Oil & Liquids Bopd	Gas Mcfpd	Total Boepd
Yemen	**3,119**	**-**	**3,119**	2,372	-	2,372
Canada	**179**	**2,987**	**677**	63	1,200	263
Total	**3,298**	**2,987**	**3,796**	2,435	1,200	2,635

RESERVES AND ESTIMATED FUTURE NET REVENUES

In 2004, DeGolyer and MacNaughton Canada Limited ("DeGolyer") of Calgary, Alberta, independent petroleum engineering consultants based in Calgary and part of the DeGolyer and MacNaughton Worldwide Petroleum Consulting group headquartered in Dallas, Texas, were retained by the Company's Reserve Committee, to independently evaluate 100% of TransGlobe's reserves as at December 31, 2004.

Prior thereto, Outtrim Szabo Associates Ltd. ("OSAL") of Calgary, Alberta (now DeGolyer and MacNaughton Canada Limited), independent petroleum engineering consultants, had historically evaluated the Company's Canadian reserves including December 31, 2003 and Fekete Associates Inc. ("Fekete") of Calgary, Alberta, independent petroleum engineering consultants, had historically evaluated the Company's reserves in Yemen including December 31, 2003.

In Yemen, proved reserves increased 95% to 4.4 million Bbls at year end 2004 from 2.3 million Bbls at year end 2003. Proved reserve increases in Yemen are in part attributed to continued performance of the Tasour field in Block 32 and the development of the An Nagyah field in Block S-1.

In Canada, proved reserves increased 51% to 2.2 million Boe at year end 2004 from 1.5 million Boe at year end 2003. The increase is attributed to the 2004 drilling program.

The Company's Reserves Committee, the majority comprised of independent directors, has reviewed and recommended acceptance of the 2004 year end reserve evaluations prepared by DeGolyer.

The 2004 and 2003 year end reserves were prepared by the Company's independent reserve evaluators in accordance with the Canadian National Instrument (NI) 51-101 policy introduced in 2003.

The (NI) 51-101 policy introduced in 2003 has adopted a P-50 level of certainty ("at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves") for Proved plus Probable reserves. Under the previous National Policy 2-B, Probable reserves were un-risked.

It is expected that the Company's International reserves reported under policy (NI) 51-101, will generally be more conservative than those booked by a joint venture partner reporting under SEC standards, especially newer reserves with little or no production history.

All reserves (gross and net) presented below are based on Forecast Pricing.

Reserves

	2004								2003	
	Light & Medium Crude Oil		**Natural Gas**		**Natural Gas Liquids**		**Total 2004 Boe's**		Total 2003 Boe's	
Company By Category	**Gross* (MBbls)**	**Net** (MBbls)**	**Gross* (MMcf)**	**Net** (MMcf)**	**Gross* (MBbls)**	**Net** (MBbls)**	**Gross* (MBoe)**	**Net** (MBoe)**	Gross* (MBoe)	Net** (MBoe)
Proved										
Producing	**2,822**	**1,882**	**6,679**	**5,373**	**139**	**99**	**4,074**	**2,876**	2,703	1,843
Non-producing	**134**	**76**	**1,231**	**883**	**105**	**73**	**444**	**297**	748	563
Undeveloped	**1,554**	**1,004**	**2,949**	**2,270**	**100**	**73**	**2,146**	**1,455**	295	217
Total Proved	**4,510**	**2,962**	**10,859**	**8,526**	**344**	**245**	**6,664**	**4,628**	3,746	2,623
Proved plus Probable	**7,334**	**4,445**	**15,749**	**12,238**	**468**	**331**	**10,427**	**6,916**	7,037	4,945

* *Gross reserves are the Company's working interest share before the deduction of royalties.*

** *Net reserves are the Company's working interest share after the deduction of royalties. Net reserves in Yemen include our share of future cost recovery and production sharing oil after the Government's royalty interest but before reserves relating to income taxes payable. Under this method, a portion of the reported reserves will increase as oil prices decrease (and vice versa) as the barrels necessary to achieve cost recovery change with prevailing oil prices.*

Reserves

	2004						2003	
	Oil & Liquids		**Gas**		**Total Boe's**		Total Boe's	
Company By Area	**Gross (MBbls)**	**Net (MBbls)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MBoe)**	**Net (MBoe)**	Gross (MBoe)	Net (MBoe)
Proved								
Yemen	**4,421**	**2,884**	**-**	**-**	**4,421**	**2,884**	2,263	1,476
Canada	**433**	**324**	**10,859**	**8,540**	**2,243**	**1,744**	1,483	1,147
Total Proved	**4,854**	**3,208**	**10,859**	**8,540**	**6,664**	**4,628**	3,746	2,623
Proved plus Probable								
Yemen	**7,217**	**4,441**	**-**	**-**	**7,217**	**4,441**	4,605	3,052
Canada	**585**	**435**	**15,749**	**12,258**	**3,210**	**2,475**	2,432	1,893
Total Proved plus Probable	**7,802**	**4,876**	**15,749**	**12,258**	**10,427**	**6,916**	7,037	4,945

Proved Reserves Reconciliation

	Yemen Oil	**Canada Oil & Liquids**	**Canada Natural Gas**	**Total Boe**
	Gross (MBbls)	**Gross (MBbls)**	**Gross (MMcf)**	**Gross (MBoe's)**
Reserves at Dec. 31, 2003	2,263	307	7,052	3,746
Extensions/Discoveries	3,019	132	5,098	4,000
Technical Revisions	282	60	(210)	307
Acquisitions	-	-	-	-
Divestitures	-	-	-	-
Economic Factors	(1)	(1)	12	-
Production	(1,142)	(65)	(1,093)	(1,389)
Reserves at Dec. 31, 2004	4,421	433	10,859	6,664

Proved Plus Probable Reserves Reconciliation

	Yemen Oil	**Canada Oil & Liquids**	**Canada Natural Gas**	**Total Boe**
	Gross (MBbls)	**Gross (MBbls)**	**Gross (MMcf)**	**Gross (MBoe's)**
Reserves at Dec. 31, 2003	4,605	437	11,969	7,037
Extensions/Discoveries	2,222	213	7,728	3,723
Technical Revisions	1,532	2	(2,871)	1,056
Acquisitions	-	-	-	-
Divestitures	-	-	-	-
Economic Factors	-	(2)	16	-
Production	(1,142)	(65)	(1,093)	(1,389)
Reserves at Dec. 31, 2004	7,217	585	15,749	10,427

Estimated Future Net Revenues

All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the Company's properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGL's and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGL's and natural gas reserves may be greater than or less than the estimates provided herein.

The estimated future net revenues presented below are calculated using the average price received during the final month of the respective reporting periods. The prices were held constant for the life of the reserves.

Present Value of Future Net Revenues, Before Income Tax*

Constant Pricing

	Dec. 31, 2004 Discounted at				Dec. 31, 2003 Discounted at			
	Undis-counted ($MM)	**10% ($MM)**	**15% ($MM)**	**20% ($MM)**	Undis-counted ($MM)	10% ($MM)	15% ($MM)	20% ($MM)
Proved								
Yemen *	**49.4**	**41.6**	**38.4**	**35.6**	18.0	15.7	14.8	14.0
Canada **	**52.8**	**37.2**	**32.3**	**28.4**	29.9	21.4	18.7	16.7
Total Proved	**102.2**	**78.8**	**70.7**	**64.0**	47.9	37.1	33.5	30.7
Proved plus Probable								
Yemen *	**78.5**	**62.5**	**56.3**	**51.1**	36.4	29.0	26.1	23.7
Canada **	**75.1**	**49.6**	**42.3**	**36.8**	48.9	31.2	26.7	23.3
Total Proved plus Probable	**153.6**	**112.1**	**98.6**	**87.9**	85.3	60.2	52.8	47.0

* *Yemen future net revenues presented are after Yemen income tax.*

** *Canadian values converted at the December 31, 2004 and December 31, 2003 exchange rates of 1.2020 and 1.2965 $US/$C respectively.*

The estimated future net revenues presented below are calculated using pricing of the respective independent engineering consulting firms.

Present Value of Future Net Revenues, Before Income Tax*

Independent Evaluators' Price Forecast

	Dec. 31, 2004 Discounted at				Dec. 31, 2003 Discounted at			
	Undis-counted ($MM)	**10% ($MM)**	**15% ($MM)**	**20% ($MM)**	Undis-counted ($MM)	10% ($MM)	15% ($MM)	20% ($MM)
Proved								
Yemen *	**43.5**	**37.5**	**34.9**	**32.6**	12.2	10.8	10.2	9.7
Canada **	**43.4**	**31.6**	**27.8**	**24.8**	19.7	14.2	12.5	11.2
Total Proved	**86.9**	**69.1**	**62.7**	**57.4**	31.9	25.0	22.7	20.9
Proved plus Probable								
Yemen *	**65.7**	**54.1**	**49.4**	**45.4**	22.0	17.2	15.3	13.7
Canada **	**61.7**	**41.8**	**36.2**	**31.9**	32.3	20.4	17.5	15.3
Total Proved plus Probable	**127.4**	**95.9**	**85.6**	**77.3**	54.3	37.6	32.8	29.0

* *Yemen future net revenues presented are after Yemen income tax.*

** *Canadian values converted at the December 31, 2004 and December 31, 2003 exchange rates of 1.2020 and 1.2965 $US/$C respectively.*

The following table summarizes the **constant pricing** used to estimate future net revenues.

	December 2004		December 2003	
	Oil US$/Bbl	**Natural Gas US$/Mcf**	Oil US$/Bbl	Natural Gas US$/Mcf
Yemen *	**39.58**	**-**	30.05	-
Canada **	**37.05**	**5.93**	27.78	5.45

* *Yemen prices are based on prices received for Yemen production (Blocks S-1 and 32 in 2004, and Block 32 in 2003) .*

** *Canadian prices are based on prices received for Canadian production converted at the December 31, 2004 and December 31, 2003 exchange rates of 1.2020 and 1.2965 $US/$C respectively.*

The following table summarizes the **independent evaluator price forecast** used to estimate future net revenues.

	WTI Oil Reference US$/Bbl			AECO Spot Gas Reference US$/Mcf	
Year	**DeGolyer 2004**	Outtrim 2003	Fekete 2003	**DeGolyer 2004***	Outtrim 2003*
2005	**45.00**	24.21	23.50	**5.72**	3.69
2006	**40.80**	23.53	23.50	**5.55**	3.57
2007	**36.41**	23.88	24.00	**5.37**	3.61
2008	**34.49**	24.24	24.48	**4.89**	3.59
2009	**32.47**	24.60	24.97	**4.58**	3.63
2010	**33.12**	24.97	25.47	**4.51**	3.67
Forecasted	**2%/yr**	1.5%/yr	2%/yr	**1.1% to 12 1.5% to16 then 2%**	1.2% to 14 then 1.5 %

* *Canadian values converted at the December 31, 2004 and December 31, 2003 exchange rates of 1.2020 and 1.2965 $US/$C respectively.*

Management's Discussion and Analysis

March 9, 2005

The following discussion and analysis is management's opinion of TransGlobe's historical financial and operating results and should be read in conjunction with the message to the shareholders, the operations review, the audited consolidated financial statements of the Company for the years ended December 31, 2004 and 2003, together with the notes related thereto. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada in the currency of the United States (except where indicated as being another currency). The effect of significant differences between Canadian and United States accounting principles is disclosed in Note 15 of the consolidated financial statements. Additional information relating to the Company, including the Company's Annual Information Form, is on SEDAR at www.sedar.com. The calculations of barrels of oil equivalent ("Boe") are based on a conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil. Boe's may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

This Management's Discussion and Analysis (MD&A) may include certain statements that may be deemed to be "forward-looking statements" within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. All statements in this annual report, other than statements of historical facts, that address future production, reserve potential, exploration drilling, exploitation activities and events or developments that the Company expects, are forward-looking statements. Although TransGlobe believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. Factors that could cause actual results to differ materially from those in forward-looking statements include, but are not limited to, oil and gas prices, exploitation and exploration successes, continued availability of capital and financing, and general economic, market or business conditions.

OVERVIEW

Cash flow from operations for 2004 increased 85% to $17,325,000 ($0.32 per share basic and $0.31 per share diluted) compared to $9,347,000 ($0.18 per share basic and $0.17 per share diluted) in 2003. Net income for 2004 was unchanged at $5,919,000 ($0.11 per share basic and $0.10 per share diluted) compared to net income of $5,905,000 ($0.11 per share basic and $0.11 per share diluted) in 2003. The Company's oil and gas revenues, net of royalties, increased 84% to $31,630,000 in 2004 compared to 2003.

The following is a brief summary of the primary changes that occurred during 2004 that will be discussed in more detail throughout this MD&A:

- Cash Flow From Operations and Net Income items:
  - Oil and gas sales, net of royalties, increased $14,468,000 (84%) as a direct result of sales volumes increasing 44% and commodity prices increasing 25%.
  - Operating costs increased $3,358,000 (32% on a Boe basis) in 2004 compared to 2003 as a result of increased volumes and Block S-1 having a higher cost per Boe during the trucking phase.
  - Current income tax expense increased $2,525,000 in 2004 compared to 2003 as a result of higher volumes with Block S-1 production commencing in 2004.

- Additional Net Income items:
  - Depletion, depreciation and accretion, a non-cash expense, increased $4,093,000 (15% on a Boe basis) in 2004 compared to 2003 due mainly to higher capital costs in the depletable base.
  - Future income tax recovery, a non-cash recovery, decreased $2,163,000 in 2004 compared to 2003 due to the initial recognition of a Canadian future income tax asset in 2003.
  - Stock-based compensation, a non-cash expense, amounted to $1,310,000 in 2004 without a corresponding amount in the same period in 2003.

Furthermore, the Company's financial condition remained strong as working capital continued to be in excess of $2.5 million and the Company continued to have no long-term debt outstanding. During the fourth quarter of 2004, the Company issued 2,910,000 shares through a public offering for net proceeds of $9.8 million.

Operating Segments

TransGlobe reports its results of operations under three main geographic segments: Republic of Yemen, Canada and Arab Republic of Egypt.

Yemen includes the Company's exploration for, as well as development and production of, crude oil. In 2004, the Company spent $15.3 million or 58% of its capital expenditures in Yemen. Of this, $12.1 million was spent at Block S-1 primarily to develop the An Nagyah field and $3.1 million was spent at Block 32 primarily to develop the Tasour field. Oil sales, net of royalties, less operating costs and depletion, depreciation and accretion increased 86% to $11.4 million in 2004 compared to $6.1 million in 2003 primarily due to Block S-1 commencing production at the end of the first quarter of 2004 and higher crude oil prices in 2004 compared to 2003.

Canada includes the Company's exploration for, as well as development and production of, natural gas, natural gas liquids ("NGLs") and crude oil. In 2004, the Company spent $10.1 million or 38% of its capital expenditures in Canada primarily on the exploration for natural gas and NGL's. Oil and gas sales, net of royalties, less operating costs and depletion, depreciation and accretion increased 159% to $2.9 million in 2004 compared to $1.1 million in 2003 primarily due to successful exploration drilling which increased production 158% in 2004 compared to 2003.

Egypt includes the Company's exploration for natural gas, natural gas liquids and crude oil. In 2004, the Company spent $1.0 million primarily on acquisition costs and geological and geophysical activity for Nuqra Block 1.

Business Environment

Commodity Price and Foreign Exchange Benchmarks

	2004	**% Change**	2003	% Change	2002
Dated Brent average oil price ($ per barrel)	**38.58**	**34**	28.87	13	25.47
WTI average oil price ($ per barrel)	**41.42**	**33**	31.14	19	26.09
Edmonton Par average oil price (C$ per barrel)	**52.91**	**22**	43.23	8	40.12
AECO average gas price (C$ per thousand cubic feet)	**6.54**	**(2)**	6.67	64	4.07
U.S./Canadian Dollar Year End Exchange Rate	**0.8319**	**8**	0.7713	22	0.6339
U.S./Canadian Dollar Average Exchange Rate	**0.7685**	**8**	0.7138	12	0.6368

World crude oil prices continued to increase significantly in 2004 as Asia and North America demand remained strong and, during the fourth quarter, concerns increased over the supply of winter heating oil supplies. Also in the fourth quarter, supply uncertainties in the Middle East and West Africa, combined with reduced supply from the Gulf of Mexico, the North Sea, Russia and Canada, increased the lack of confidence concerning future world crude oil supply, resulting in the continued upward pressure on prices in 2004.

In 2004, TransGlobe sold approximately:

- 5% of its crude oil at fixed prices;
- 92% at dated Brent minus the Yemen government official selling price differentials; and
- the remaining 3% at the Edmonton Par price less quality differentials.

Historically high natural gas prices continued in 2004 since North American demand remained strong which, combined with a lack of supply and high crude oil prices, influenced natural gas prices.

In 2004, TransGlobe sold approximately:

- 29% of its natural gas at fixed prices; and
- the remaining 71% at AECO Index based pricing.

The year end U.S./Canadian dollar exchange rate increased by 8% in 2004 to US$0.8319/C$1 compared to US$0.7713/C$1 in 2003 and increased 22% in 2003 to US$0.7713/C$1 compared to US$0.6339/C$1 in 2002. The increases in each year were primarily the result of the economic slowdown in the U.S., continuing differences between Canadian and U.S. interest rates and the U.S. current account deficits.

Management Strategy

In 2005, the capital budget is expected to be focused on the completion of the central production facility and related pipeline on the An Nagyah field in Block S-1, as well as growing reserves and production in Yemen and Canada. Also, a significant portion of the 2005 capital budget will be spent defining leads on Nuqra Block 1 in Egypt through geological field studies, reprocessing of existing 2-D seismic and field acquisition of additional 2-D seismic to identify drilling locations for the 2006 exploration program.

The success of these strategies is subject to numerous risk factors such as (including but not limited to) exploration success, fluctuations in commodity prices and foreign exchange rates, in addition to credit, operational and safety and environmental risks.

SELECTED ANNUAL AND QUARTERLY INFORMATION

($000's, except per share amounts and % change)	**2004**	**% Change**	2003 Restated	% Change	2002
Average sales volumes (Boepd)	**3,796**	**44**	2,635	52	1,731
Average price ($/Boe)	**35.63**	**25**	28.43	17	24.34
Oil and gas sales	**49,495**	**81**	27,336	78	15,386
Oil and gas sales, net of royalties	**31,630**	**84**	17,162	29	13,254
Cash flow from operations	**17,325**	**85**	9,347	(4)	9,710
Cash flow from operations per share					
- Basic	**0.32**		0.18		0.19
- Diluted	**0.31**		0.17		0.19
Net income	**5,919**	**-**	5,905	9	5,426
Net income per share					
- Basic	**0.11**		0.11		0.11
- Diluted	**0.10**		0.11		0.10
Total assets	**60,522**	**70**	35,601	46	24,386

	2004			
($000's, except per share amounts)	**Q-4**	**Q-3**	**Q-2**	**Q-1**
Average sales volumes (Boepd)	**5,384**	**3,918**	**3,103**	**2,760**
Average price ($/Boe)	**$ 37.45**	**$ 37.12**	**$ 34.25**	**$ 31.44**
Oil and gas sales	**$ 18,548**	**$ 13,380**	**$ 9,670**	**$ 7,897**
Oil and gas sales, net of royalties	**$ 11,756**	**$ 8,227**	**$ 5,779**	**$ 5,868**
Cash flow from operations	**$ 6,326**	**$ 4,363**	**$ 2,749**	**$ 3,887**
Cash flow from operations per share				
- Basic	**$ 0.12**	**$ 0.08**	**$ 0.05**	**$ 0.07**
- Diluted	**$ 0.11**	**$ 0.08**	**$ 0.05**	**$ 0.07**
Net income	**$ 768**	**$ 2,541**	**$ 447**	**$ 2,163**
Net income per share				
- Basic	**$ 0.01**	**$ 0.05**	**$ 0.01**	**$ 0.04**
- Diluted	**$ 0.01**	**$ 0.04**	**$ 0.01**	**$ 0.04**

	2003			
($000's, except per share amounts)	Q-4	Q-3	Q-2	Q-1
Average sales volumes (Boepd)	2,819	2,698	2,499	2,517
Average price ($/Boe)	$ 28.90	$ 28.29	$ 26.39	$ 30.08
Oil and gas sales	$ 7,496	$ 7,021	$ 6,002	$ 6,817
Oil and gas sales, net of royalties	$ 4,489	$ 4,159	$ 4,139	$ 4,375
Cash flow from operations	$ 1,894	$ 2,193	$ 2,369	$ 2,891
Cash flow from operations per share				
- Basic	$ 0.04	$ 0.04	$ 0.05	$ 0.06
-Diluted	$ 0.03	$ 0.04	$ 0.05	$ 0.06
Net income	$ 3,413	$ 291	$ 776	$ 1,425
Net income per share				
- Basic	$ 0.06	$ 0.01	$ 0.01	$ 0.03
- Diluted	$ 0.06	$ 0.01	$ 0.01	$ 0.03

Cash flow from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital. We consider this a key measure as it demonstrates our ability to generate the cash flow necessary to fund future growth through capital investment. Cash flow from operations may not be comparable to similar measures used by other companies.

Discussion of Annual Information:

Cash flow from operations increased by $7,978,000 (85%) in 2004 compared to 2003 mainly as a result of:

- increased volumes from drilling success in both Yemen and Canada;
- increased commodity prices; and
- increased operating costs and current taxes due to higher volumes that offset the above cash increases.

Net income was unchanged in 2004 compared to 2003 mainly as result of:

- the above items affecting cash flow also increased net income, and are offset by:
  - increased depletion, depreciation and accretion due to higher capital costs in the depletable base;
  - increased stock-based compensation, a non-cash expense, due to a new Canadian accounting standard; and
  - decreased non-cash future income tax recovery in 2004 compared to 2003.

Discussion of Quarterly Information:

Oil and gas sales, net of royalties, and cash flow from operations increased in the third and fourth quarters of 2004 due to increased production relating primarily to Block S-1 commencing production at the end of the first quarter with increased trucking capacity each quarter, increasing production in Canada due to the success of the drilling program and crude oil prices increasing throughout 2004.

Net income is higher in the third quarter of 2004 due a non-cash future income tax recovery booked that relates to the Company recognizing a portion of the future tax benefits in Canada as a direct result of the successful Canadian drilling program carried out in 2004. Net income is also higher in the fourth quarter of 2003 due a non-cash future income tax recovery booked that relates to the Company recognizing a portion of the future tax benefits in Canada as a direct result of the successful Canadian drilling program carried out in 2003 and recording a gain in the United States on disposal of seismic data.

OPERATING RESULTS

Daily Production, before royalties

		2004	2003	% Change
Yemen - Oil	Bopd	**3,119**	2,372	31
Canada - Oil and liquids	Bopd	**179**	63	184
- Gas	Mcfpd	**2,987**	1,200	149
Barrels of oil equivalent (6:1)	Boepd	**3,796**	2,635	44

Consolidated Net Operating Results

	Consolidated			
	2004		2003	
(000's, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
Oil and gas sales	**49,495**	**35.63**	27,336	28.43
Royalties	**17,865**	**12.86**	10,174	10.58
Operating expenses	**7,064**	**5.09**	3,706	3.85
Net operating income*	**24,566**	**17.68**	13,456	14.00

* *Net operating income amounts do not reflect Yemen income tax expense which is paid through oil allocations with MOM in Yemen (2004 - $5,269,000, $3.79/Boe; 2003 - $2,755,000, $2.87/Boe).*

Segmented Net Operating Results

In 2004 the Company had producing operations in two geographic areas, segmented as Yemen and Canada. Also, the Company had start-up operations in a third geographic segment, Egypt. MD&A will follow under each of these segments.

Republic of Yemen

	2004		2003	
(000's, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
Oil sales	**41,472**	**36.33**	24,356	28.13
Royalties	**16,506**	**14.46**	9,731	11.24
Operating expenses	**5,449**	**4.77**	3,012	3.48
Net operating income*	**19,517**	**17.10**	11,613	13.41

* *Net operating income amounts do not reflect Yemen income tax expense which is paid through oil allocations with MOM in Yemen (2004 - $5,269,000, $4.62/Boe; 2003 - $2,755,000, $3.18/Boe.)*

Net operating income in Yemen increased 68% in 2004 primarily as a result of the following:

- Oil sales increased 70% mainly as a result of the following:
    1. Sales volumes increased 31% in 2004 primarily as a result of Block S-1 production commencing at the end of the first quarter 2004. During 2004 sales volumes for Block S-1 and Block 32 were 666 Bopd and 2,453 Bopd, respectively.
    2. Oil prices increased 29%.

- Royalty costs increased 70%. Royalties as a percentage of revenue were consistent at 40% in 2004 and 2003.

- Operating expenses on a Boe basis increased 37% mainly as a result of the following:
    1. Block 32 operating expenses averaged $4.11 per barrel in 2004 compared to $3.48 per barrel in 2003 primarily due to diesel costs which increased approximately $0.42 per barrel. A plant is being constructed in 2005 to manufacture diesel from produced crude oil which will reduce the cost of purchased diesel. The plant is expected to be commissioned in the third quarter of 2005.
    2. Block S-1 has significantly higher operating costs during the initial trucking phase, averaging $7.96 per barrel. This is a reflection of higher costs associated with trucking and higher fixed costs per barrel until volumes are increased when full scale production commences in 2005. Average cost per barrel is expected to be significantly reduced after commissioning of the pipeline and with increased production in mid 2005.

TransGlobe commenced production on Block 32 on November 4, 2000. Production from the block is shared between the Block 32 Joint Venture Group and MOM pursuant to a PSA. The PSA provides for MOM to receive a 3% royalty of gross production (10% over 25,000 Bopd) with the remaining 97% of production split between cost recovery oil and production sharing oil. Cost recovery oil is up to a maximum of 60% of the production after deducting royalty. Cost recovery oil allows the Block 32 Joint Venture Group to recover operating costs and exploration and development expenditures as outlined in the PSA. The remaining oil is allocated to production sharing oil shared 65% by MOM and 33.25% by the Block 32 Joint Venture Group and 1.75% to YOC. The Block 32 Joint Venture Group's Yemen income taxes are paid out of the MOM's share of production sharing oil. These terms remain in place until gross proved recoverable reserves exceed 30 million barrels of oil (assessed every two years) or until gross production exceeds 25,000 Bopd at which time the terms would revert to the original PSA terms in place prior to the 1999 PSA amendment. The original PSA terms provided for a 10% royalty on gross production with the remaining 90% of production split between cost recovery oil and production sharing oil. Cost recovery oil would be to a maximum of 25%, with the remaining oil allocated to production sharing oil shared 77% by MOM and 23 % by the Block 32 Joint Venture Group. The proved recoverable reserve determination is conducted every 2 years from the anniversary of first oil production (November 4, 2000). At November 4, 2004, the proved recoverable reserves recognized by the MOM approved independent third party audit was less than 10 million barrels. The next Block 32 MOM audit will be conducted effective November 4, 2006.

The current Block 32 Production Sharing agreement allows for the recovery of operating costs and capital costs from oil production. Operating costs are recovered in the quarter expended. The capital costs are amortized over two years with 50% recovered in the quarter expended and the remaining 50% recovered in the first quarter of the following calendar year. The Company will receive a larger share of production in the first quarter of each year as 50% of the previous year's historical costs are recovered. The amount of oil required to recover capital and operating costs will vary depending upon the prevailing oil prices. The Company received 43% of its working interest share of production (after royalty and tax) in 2004 compared to 49% in 2003. The Company expects to receive between 65% to 71% share of production (after royalty and tax) in the first quarter of 2005 and then decrease to between 39% to 45% share of production (after royalty and tax) in the balance of the year depending upon production volumes, oil prices, operating costs and eligible capital expenditures.

TransGlobe commenced production on Block S-1 on March 31, 2004, by commencing an early production scheme utilizing trucks. Production from the block is shared between the Block S-1 Joint Venture Group and MOM pursuant to a PSA. The PSA provides for MOM to receive a 3% royalty of gross production up to 12,500 Bopd (4% royalty from 12,500 to 25,000 Bopd) with the remaining 97% of production split between cost recovery oil and production sharing oil. Cost recovery oil is up to a maximum of 50% of the production after deducting royalty. Cost recovery oil allows the Block S-1 Joint Venture Group to recover operating costs and exploration and development expenditures as outlined in the PSA. The remaining oil is allocated to production sharing oil shared 65% by MOM and 28.875% by the Block S-1 Joint Venture Group and 6.125% to YOC up to 12,500 Bopd (70% by MOM and 24.75% by the Block S-1 Joint Venture Group and 5.25% to YOC from 12,500 Bopd to 25,000 Bopd). The Block S-1 Joint Venture Group's Yemen income taxes are paid out of the MOM's share of production sharing oil.

The Block S-1 Production Sharing agreement allows for the recovery of operating costs and capital costs from oil production. Operating costs are recovered in the quarter expended. New capital costs are amortized over eight quarters with one eighth (12.5%) recovered each quarter. In addition to current ongoing investments, the Company will also recover eligible historical costs on a "last in, first out" basis. The Company received maximum cost oil for all of 2004. The amount of oil required to recover capital and operating costs will vary depending upon the prevailing oil prices, operating costs and the amount of new capital invested. It is expected that the Company will continue to receive the maximum cost oil resulting in a 62.5% of its working interest share of production (net barrels, after royalty and tax) for 2005.

Canada

	2004		2003	
(000's, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
Oil sales	**1,201**	**38.34**	345	27.00
Gas sales (6:1)	**5,675**	**31.14**	2,293	31.44
NGL sales	**1,070**	**31.37**	236	23.42
Other sales	**77**	**-**	106	-
	8,023	**32.40**	2,980	31.10
Royalties	**1,359**	**5.49**	443	4.62
Operating expense	**1,615**	**6.52**	694	7.25
Net operating income	**5,049**	**20.39**	1,843	19.23

Net operating income in Canada increased 174% in 2004 primarily as a result of the following:

- Sales increased 169% mainly as a result of the following:
    1. Sales volumes increased 158% as a direct result of the 2003 and 2004 drilling programs.
    2. Commodity prices increased 4% on a Boe basis. More specifically, gas prices decreased 1% to average $5.19 per Mcf in 2004 compared to $5.24 per Mcf in 2003 while oil and natural gas liquids prices increased 42% and 34%, respectively.

- Royalty costs increased 19% on a Boe basis. Royalties as a percentage of revenue increased to 17% in 2004 compared to 15% in 2003 mainly as a result of the new wells that were placed on production in the second half of 2004, which have a higher royalty rate as a percentage of revenue than the previous wells on production.

- Operating costs decreased 10% on a Boe basis as a result of wells that were placed on production in 2004, which have a lower operating cost than the previous wells on production. This was offset by the strengthening of the Canadian dollar which increased Canada's operating costs when converted to US dollars at a higher rate.

Egypt

TransGlobe Petroleum Egypt Inc. ("TransGlobe Egypt"), a wholly owned subsidiary of TransGlobe Energy Corporation, entered into a Farmout Agreement which provides TransGlobe Egypt the opportunity to participate and earn a 50% working interest in the Nuqra Concession by paying 100% of the initial $6.0 million of expenditures in the Stage 1 and Stage 2 work programs. TransGlobe Egypt is the operator of the Nuqra Block. The Nuqra Concession Agreement Stage 1 work program requires a minimum expenditure of $2.0 million to reprocess existing seismic and to shoot new seismic within the first two years. Upon expiry of the Stage 1 term, there is an option to proceed to the Stage 2 work program. Stage 2 requires completion of a two well drilling program, with a minimum expenditure of $4.0 million, over a period of three years. Upon expiry of the Stage 2 term there is an option to proceed to the Stage 3 work program. Stage 3 requires completion of a two well drilling program, with a minimum expenditure of $5.0 million, over a final three year term. Exploitation of discovered commercial fields will continue under a Development Lease for a further 20 years.

The Concession fiscal terms allow for the recovery of costs of up to a maximum of 40% of gross production. The remaining balance of production is then shared on a 70:30 basis between the government and the contractor (Nuqra Block Joint Venture Group), respectively for the first 25,000 Bopd. Production sharing above 25,000 Bopd is shared on an 80:20 basis.

The Company spent $992,000 in 2004 primarily on acquisition costs and geological and geophysical activities related to the Nuqra Block. The proposed work program for 2005 consists of geological field studies, re-processing of existing 2-D seismic and field acquisition of additional 2-D seismic data. It is anticipated that exploration drilling will commence late 2006.

The Nuqra Concession is located in Upper Egypt near the city of Luxor on the east bank of the Nile River. The concession encompasses over two-thirds of the Kom Ombo Basin, a rift basin analogous to the Gulf of Suez Basin in Egypt, the Marib Basin in Yemen, and the Muglad Basin in Sudan, all of which contain major reserves. The Nuqra Concession contains more than 30,000 square kilometers or 7,500,000 acres of exploration lands with 13 seismically defined leads identified from over 4,000 km of existing 2-D seismic. Seismic and well data have confirmed the existence of Jurassic and Cretaceous sediments and the presence of a petroleum system which could potentially hold significant oil reserves.

GENERAL AND ADMINISTRATIVE EXPENSES

	2004		2003	
(000's, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
G&A (gross)	**2,862**	**2.06**	1,569	1.63
Capitalized G&A	**(1,011)**	**(0.73)**	(278)	(0.29)
Overhead recoveries	**(187)**	**(0.13)**	(84)	(0.09)
G&A (net)	**1,664**	**1.20**	1,207	1.25

General and administrative expenses ("G&A") increased 38% in 2004 compared to 2003 and decreased 4% on a Boe basis, as a result of the following:

- Increases were experienced in personnel costs with additional employees and consultants, office overhead costs and insurance costs.
- Public company administration costs increased 16% in 2004 and are anticipated to be higher in 2005 due to additional work associated with Sarbanes Oxley compliance.
- Capitalized general and administrative expenses and overhead recoveries increased due to the increased capital activity in both Yemen and Canada.
- The strengthening of the Canadian dollar against the United States dollar increased net G&A costs by $0.10 per Boe through currency conversion.

STOCK-BASED COMPENSATION

Effective January 1, 2004 the Company adopted the new accounting standard of Canadian Institute of Chartered Accountants ("CICA") section 3870, "Stock-based Compensation and Other Stock-based Payments", retroactively without restatement of prior periods. This Canadian accounting standard requires the Company to record a compensation expense over the vesting period based on the fair value of options granted to employees and directors since January 1, 2002. Non-cash stock compensation expense amounted to $1,310,000 ($0.94/Boe) for 2004.

DEPLETION, DEPRECIATION AND ACCRETION EXPENSE

	2004		2003	
(000's, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
Republic of Yemen	**8,162**	**7.15**	5,516	6.37
Canada	**2,184**	**8.82**	737	7.69
	10,346	**7.45**	6,253	6.50

In Yemen, depletion, depreciation and accretion ("DD&A") on a Boe basis increased 12% in 2004 compared to 2003 primarily as a result of an increased asset base as all remaining costs associated with the Block S-1 major development project were included in the depletable base. In 2003, major development project costs of $11,684,000 were excluded from costs subject to depletion and depreciation representing a portion of the costs incurred in Block S-1.

In Canada, DD&A on a Boe basis increased 15% in 2004 compared to 2003 primarily as a result of the strengthening of the Canadian dollar against the United States dollar which increased DD&A $0.59 per Boe (8%) through currency conversion.

INCOME TAXES

($000's)	**2004**	2003
Future income tax	**(285)**	(2,448)
Current income tax	**5,280**	2,755
	4,995	307

The future income tax recovery of $285,000 in 2004 and $2,448,000 in 2003 is a result of recognizing a portion of the future tax benefits in Canada. The recording of these future tax benefits in Canada is a direct result of the successful Canadian drilling program carried out in 2004 and 2003. The Company has unrecognized future tax benefits in Canada in the amount of $599,000 which may be recognized in the future with continued drilling successes in Canada.

Current income tax expense in 2004 of $5,280,000 (2003 - $2,755,000) represents income taxes of $5,269,000 (2003 - $2,755,000) incurred and paid under the laws of Yemen pursuant to the PSA on Block 32 and Block S-1 and $11,000 paid in Canada. The increase in Yemen is primarily the result of the following:

- Increased volumes mainly as a result of production start up on Block S-1.

- Increase in oil prices.

- An increase in the Yemen government's share of production sharing oil on Block 32 as a result of recovery of all historical costs during Q2-2003. The Yemen government's share of production sharing oil includes royalties and taxes.

CAPITAL EXPENDITURES/DISPOSITIONS

Capital Expenditures

($000's)	**2004**	2003
Republic of Yemen	**15,275**	9,012
Canada	**10,100**	5,217
Egypt	**992**	-
	26,367	14,229
Proceeds on sale of property and equipment	**-**	(442)
Net capital expenditures	**26,367**	13,787

Capital expenditures in 2004 are mainly comprised of the following:

Block 32, Yemen ($3,110,000)
- 3-D seismic program at Tasour, Tasour facility upgrades and drilling 3 oil wells at Tasour.

Block S-1, Yemen ($12,131,000)
- Drilling and completing of eight oil wells at An Nagyah, drilling one oil well at Harmel, drilling one D&A well at Al Hareth and costs associated with commercial development of the An Nagyah field.

Other, Yemen ($34,000)
- Mainly costs associated with obtaining Block 72 in Yemen.

Nuqra Block 1, Egypt ($992,000)
- Mainly costs associated with acquiring the Block, plus geological and geophysical costs.

Canada ($10,100,000)
- Costs mainly related to the drilling of fifteen wells (11.4 net wells) and related tie-in of seven of these wells (five gas, two oil) as part of the 2004 exploration and development program.
- Costs also related to the re-completion of four wells, of which three (two gas, one oil) came on production, and the tie-in of two wells (one gas, one oil) drilled in prior years.
- Other costs related to oil and gas lease acquisitions for future drilling associated with the 2004 and 2005 exploration and development programs.

The dispositions of $442,000 in 2003 are related to proceeds on disposal of minor oil and gas properties in Canada for $79,000 and proceeds on disposal of seismic data in the United States for $363,000. A gain on disposition of the seismic data in the United States was recorded in other income as there is no associated cost base in this cost centre.

FINDING AND DEVELOPMENT COSTS

Proved ($000's, except per Boe and $/Boe amounts)	**2004**	2003	2002
Total capital expenditure	**26,367**	14,229	6,477
Net change from previous year's future capital	**8,796**	2,159	634
	35,163	16,388	7,111
Reserve additions and revisions (MBoe)	**4,332**	2,360	1,210
Average cost per Boe	**8.12**	6.94	5.88
Three year average cost per Boe	**7.42**	6.40	6.75

Proved plus Probable ($000's, except per Boe and $/Boe amounts)	**2004**	2003	2002
Total capital expenditure	**26,367**	14,229	6,477
Net change from previous year's future capital	**597**	11,303	466
	26,964	25,532	6,943
Reserve additions and revisions (MBoe)	**4,804**	4,872	1,390
Average cost per Boe	**5.61**	5.24	4.99
Three year average cost per Boe	**5.37**	5.47	6.36

The finding and development costs shown above have been calculated in accordance with Canadian National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities introduced in 2003.

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

RECYCLE RATIO

Proved	**Three Year Average**	**2004**	2003	2002
Netback ($/Boe)	**$ 12.19**	**$ 12.46**	$ 9.72	$ 15.36
Proved finding and development costs ($/Boe)	**$ 7.42**	**$ 8.12**	$ 6.94	$ 5.88
Recycle ratio	**1.64**	**1.53**	1.40	2.61

Proved plus Probable	**Three Year Average**	**2004**	2003	2002
Netback ($/Boe)	**$ 12.19**	**$ 12.46**	$ 9.72	$ 15.36
Proved plus Probable finding and development costs ($/Boe)	**$ 5.37**	**$ 5.61**	$ 5.24	$ 4.99
Recycle ratio	**2.27**	**2.22**	1.85	3.08

The 2004 recycle ratio was consistent with 2003. The decrease in the 2003 recycle ratio to 1.40 compared to 2002 of 2.61 mainly relates to a lower netback in Yemen in 2003 which is a result of historical cost pool allocations between partners and achieving full historical cost pool recovery during Q2 2003.

The recycle ratio is a non-GAAP measure that measures the efficiency of TransGlobe's capital program by comparing the cost of finding and developing proved reserves with the netback from production. The ratio is calculated by dividing the netback per Boe by the proved or proved plus probable finding and development cost on a Boe basis. Netback is defined as:

($000's, except volumes and per Boe amounts)	**2004**	2003	2002
Net income	**5,919**	5,905	5,426
Adjustments for non-cash items:			
Depletion, depreciation and accretion	**10,346**	6,253	4,277
Stock-based compensation	**1,310**	-	-
Future income taxes	**(285)**	(2,448)	(67)
Amortization of deferred financing costs	**35**	-	-
Gain on sale of property and equipment	**-**	(363)	-
Performance bonus expense paid in shares	**-**	-	74
Netback	**17,325**	9,347	9,710
Sales Volumes	**1,389,920**	961,588	632,018
Netback per Boe	**12.46**	9.72	15.36

OUTSTANDING SHARE DATA

Common Shares issued and outstanding as at March 9, 2005 are 57,200,939.

FOURTH QUARTER

During the fourth quarter of 2004, gross oil and gas sales increased 39% to $18,548,000 compared to the third quarter 2004 primarily due to sales volumes increasing 37% to 5,384 Boe per day in the fourth quarter 2004 from 3,918 Boe per day in the third quarter 2004. The increased sales volumes related primary to Block S-1 in Yemen where the Company increased trucking capacity and in Canada due to the success of the 2004 summer drilling program.

Net operating income (revenues less royalties and operating expenses) per Boe remained consistent in the fourth quarter 2004 at $18.05 per Boe compared to $17.91 in the third quarter 2004.

General and administrative expenses increased 204% in the fourth quarter 2004 to $680,000 compared to $224,000 in the third quarter 2004 primarily as a result increased personnel, insurance and public company costs.

Stock-based compensation expense increased 19% to $452,000 in the fourth quarter 2004 compared to $381,000 in the third quarter 2004 due to new employee stock option grants.

Depletion, depreciation and accretion increased 61% to $4,197,000 in the fourth quarter 2004 compared to $2,601,000 in the third quarter 2004 primarily due to increased production volumes and increased capital costs. On a Boe basis, DD&A increased 17% to $8.47 per Boe in the fourth quarter 2004 compared to $7.22 per Boe in the third quarter 2004.

A future income tax asset was recorded in the third quarter 2004 for $1,160,000. Since a portion of the asset was utilized in the fourth quarter, the Company recorded $874,000 in future income tax expense in the fourth quarter 2004 and reduced the future income tax asset.

During the fourth quarter 2004, the Company issued 2,910,000 shares through a public offering for net proceeds of $9,842,000 (net of costs) and entered into a new $7,000,000 loan facility.

LIQUIDITY AND CAPITAL RESOURCES

Funding for the Company's capital expenditures in 2004 was provided by cash flow from operations, working capital and equity financing.

At December 31, 2004 the Company had working capital of $2,839,000, zero debt and an unutilized loan facility of $7,000,000. Working capital remained consistent with the prior year. Accounts receivable increased due primarily to Block S-1, Yemen, revenue receivables. This was offset by increased accounts payable due primarily to increased capital expenditures in late 2004 related to the An Nagyah facility and pipeline at Block S-1, Yemen, and increased operating activity in Canada.

The Company expects to fund its 2005 exploration and development program (budgeted at $32 million firm and contingent) through the use of working capital, cash flow and debt. The use of our credit facilities during 2005 is expected to remain within conservative guidelines of a debt to cash flow ratio of less than 0.5:1. The Company raised $9.8 million (net after costs) on a bought deal equity financing in November and December 2004 to partially fund the Egyptian, Yemen and Canadian exploration program. This amount is included in the working capital at December 31, 2004. Equity financing may be utilized in the future to accelerate existing projects or to finance new opportunities. Fluctuations in commodity prices, product demand, foreign exchange rates, interest rates and various other risks may impact capital resources.

In December 2003, the Company issued flow through shares with terms providing that the Company renounce Canadian tax deductions in the amount of C$3,000,000 to subscribers with the entire amount to be expended by the Company by December 31, 2004. As at December 31, 2004 the Company has fulfilled this expenditure commitment.

COMMITMENTS AND CONTINGENCIES

As part of its normal business, the Company entered into arrangements and incurred obligations that will impact the Company's future operations and liquidity. The principal commitments of the Company are as follows:

($000's)	2005	2006	2007	2008	2009
Office and equipment leases	191	243	235	328	348

In June 2004, the Company entered into a one year fixed price contract to sell 10,000 barrels of oil per month in Block 32 commencing July 1, 2004 at $33.90 per barrel for dated Brent plus or minus the Yemen Government's official selling price differential.

In December 2003, the Company issued flow through shares with terms providing that the Company renounce Canadian tax deductions in the amount of C$3,000,000 to subscribers with the entire amount to be expended by the Company by December 31, 2004. The Company has fulfilled this expenditure commitment.

Pursuant to the Company's farm-in agreement on the Nuqra Concession in Egypt, the Company is committed to spend $6 million over the next 5 years to earn its 50% working interest. As part of this commitment the Company issued a $2 million letter of credit on July 8, 2004 to Ganoub El Wadi Holding Petroleum Company which expires on February 14, 2007. This letter of credit is secured by a guarantee granted by Export Development Canada.

Upon the determination that proved recoverable reserves are 40 million barrels or greater for Block S-1, Yemen, the Company will be required to pay a finders' fee to third parties in the amount of $281,000.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in accordance with generally accepted accounting principles requires that management make appropriate decisions with respect to the selection of accounting policies and in formulating estimates and assumptions that affect the reported amount of assets, liabilities, revenues and expenses. The following is included in MD&A to aid the reader in assessing the critical accounting policies and practices of the Company. The information will also aid in assessing the likelihood of materially different results being reported depending on management's assumptions and changes in prevailing conditions which affect the application of these policies and practices. Significant accounting policies are disclosed in Note 1 of the consolidated financial statements.

Oil and Gas Reserves

TransGlobe's proved and probable oil and gas reserves are 100 percent evaluated and reported on by independent petroleum engineering consultants. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery based on cash flow forecasts.

Full Cost Accounting for Oil and Gas Activities

Depletion and Depreciation Expense

TransGlobe follows the Canadian Institute of Chartered Accountants' guideline on full cost accounting in the oil and gas industry to account for oil and gas properties. Under this method, all costs associated with the acquisition of, exploration for, and the development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of depreciation, depletion and amortization. A downward revision in a reserve estimate could result in a higher DD&A charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates (see asset impairment discussion below), the excess must be written off as an expense charged against earnings. In the event of a property disposition, proceeds are normally deducted from the full cost pool without recognition of a gain or loss unless there is a change in the DD&A rate of 20 percent or greater.

Unproved Properties

Certain costs related to unproved properties and major development projects are excluded from costs subject to depletion and depreciation until the earliest of a portion of the property becomes capable of production, development activity ceases or impairment occurs. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

Asset Impairments

Under full cost accounting, a ceiling test is performed to ensure that unamortized capitalized costs in each cost centre do not exceed their fair value. An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than carrying amount, the impairment loss is limited to an amount by which the carrying amount exceeds the sum of:

i) the fair value of reserves; and
ii) the costs of unproved properties that have been subject to a separate impairment test.

Income Tax Accounting

The Company has recorded a future income tax asset in 2003 and 2004. This future income tax asset is an estimate of the expected benefit that will be realized by the use of deductible temporary differences in excess of carrying value of the Company's Canadian property and equipment against future estimated taxable income. These estimates may change substantially as additional information from future production and other economic conditions such as oil and gas prices and costs become available.

Currency Translation

The accounts of self-sustaining operations are translated using the current rate method, whereby assets and liabilities are translated at year-end exchange rates, and revenues and expenses are translated using average annual rates. Translation gains and losses relating to the self-sustaining operations are included as a separate component of shareholders' equity.

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statement of Earnings.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

Asset Retirement Obligations

Effective January 1, 2004 the Company retroactively adopted the Canadian Institute of Chartered Accountants ("CICA") section 3110, "Asset Retirement Obligations". The new recommendations require the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion expense which is included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset. Previously the Company used the unit-of-production method to match estimated future retirement costs with revenues generated from producing assets. Note 2a discloses the impact of the adoption of CICA section 3110 on the financial statements.

Property and Equipment

Effective January 1, 2004 the Company adopted Accounting Guideline 16, "Oil and Gas Accounting - Full Cost" ("AcG-16"), which replaces Accounting Guideline 5, "Full Cost Accounting in the Oil and Gas Industry". AcG-16 modifies how the ceiling test is performed and is consistent with CICA section 3063, "Impairment of Long-lived Assets". The recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value. This approach incorporates risks and uncertainties in the expected future cash flows which are discounted using a risk free rate. The adoption of AcG-16 had no effect on the Company's financial results.

Impairment of Long Lived Assets

Effective January 1, 2004 the Company adopted CICA section 3063, "Impairment of Long-lived Assets", which had no effect on the consolidated financial statements.

Stock-based Compensation

Effective January 1, 2004 the Company adopted the new accounting standard of CICA section 3870, "Stock-based Compensation and Other Stock-based Payments", retroactively without restatement of prior periods. This Canadian accounting standard requires the Company to record a compensation expense over the vesting period based on the fair value of options granted to employees and directors since January 1, 2002. Note 2d discloses the impact of the adoption of CICA section 3870 on the financial statements.

Currency Translation

As a result of the increase in cash flow from Canadian operations, the Company reviewed its accounting practices for operations in Canada and determined that such operations are self-sustaining. The accounts of self-sustaining Canadian operations are translated using the current rate method, whereby assets and liabilities are translated at period-end exchange rates and revenues and expenses are translated using average rates for the period. Translation gains and losses relating to the operations are deferred and included as a separate component of shareholders' equity. Note 2e discloses the impact of the change in accounting practise related to currency translation.

Previously, Canadian operations were considered to be integrated and translated using the temporal method. Under the temporal method, monetary assets and liabilities were translated at the period end exchange rate, other assets and liabilities at the historical rates and revenues and expenses at the average monthly rates except depreciation, depletion and amortization, which were translated on the same basis as the related assets.

Accounting for Derivative Instruments and Hedging Activities

Effective January 1, 2004 the Company adopted CICA Accounting Guideline 13, "Hedging Relationships" ("AcG-13"). AcG-13 has essentially the same criteria to be satisfied before the application of hedge accounting is permitted as the corresponding requirements of the Financial Accounting Standards Board ("FASB") Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133").

This accounting standard requires that every derivative instrument, including certain derivative instruments embedded in other contracts, be recorded on the balance sheet as either an asset or liability measured at fair value. These standards further establish that changes in the fair value be recognized currently in earnings unless the arrangement can meet the "effective hedge" criteria. The adoption of AcG-13 had no effect on the Company's financial results.

NEW ACCOUNTING STANDARDS

On November 1, 2004, a new CICA Accounting Guideline AcG-15 "Consolidation of Variable Interest Entities" was introduced. AcG-15 defines a variable interest entity ("VIE") as a legal entity in which either the total equity at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support provided by other parties or the equity owners lack a controlling financial interest. The guideline requires the enterprise which absorbs the majority of a VIE's expected gains or losses, the primary beneficiary, to consolidate the VIE.

The adoption of AcG-15 is expected to have no effect on the Company's financial results.

RISKS

The Company is exposed to a variety of business risks and uncertainties in the international petroleum industry including commodity prices, exploration success, production risk, foreign exchange, interest rates, government regulation, changes of laws affecting foreign ownership, political risk of operating in foreign jurisdictions, taxes, environmental preservation and safety concerns.

Many of these risks are not within the control of management, but the Company has adopted several strategies to reduce and minimize the effects of these factors:

- The Company applies rigorous geological, geophysical and engineering analysis to each prospect.
- The Company utilizes its in-house expertise for all international ventures and employs and contracts professionals to handle each aspect of the Company's business.
- The Company maintains U.S. dollar bank accounts which is its main operating currency.
- The Company maintains a conservative approach to debt financing and currently has no long-term debt.
- The Company maintains insurance according to customary industry practice, but cannot fully insure against all risks.
- The Company conducts its operations to ensure compliance with government regulations and guidelines.
- The Company retains independent petroleum engineering consultants to determine year-end Company reserves and estimated future net revenues.
- The Company manages commodity prices by entering physical fixed price sales contracts when deemed appropriate.

OUTLOOK

2005 Production Outlook

		2005	2004	Change (*)
Barrels of oil equivalent (6:1)	Boepd	**5,800 to 6,200**	3,796	58%

(*) % growth based on mid point of guidance

2005 Cash Flow From Operations Outlook

($000's)	2005(*)	2004	Change (*)
Cash flow from operations	**32,000**	17,325	85%

(*) Based on an average of 6,000 Boepd, a dated Brent oil price of $38.00/Bbl and an AECO gas price of C $6.00/Mcf.

Sensitivity

($000's)	2005 Cash Flow from Operations Increase
$1.00 per barrel increase in dated Brent	815
C$0.10 per Mcf increase in AECO	120

2005 Capital Budget

($000's)	2005
Canada	9,000
Yemen - Block S1	11,000
- Block 32	4,000
- Block 72	2,000
Egypt	5,600
Other	400
Total	32,000

TransGlobe plans to continue increasing crude oil production on Block 32 and Block S-1 in Yemen and natural gas production in Canada to deliver near term growth, with Block 72 in Yemen contributing to medium term growth and Nuqra Block 1 in Egypt adding to longer term growth. For the near term growth, the Company expects to drill 15 wells in Yemen during 2005 of which 7 wells will be development wells and 8 wells will be exploration wells. In Canada, the Company plans on drilling 15 wells during 2005 split evenly between development and exploration wells. The Company attaches a significantly higher risk to the exploratory wells. The 2005 capital budget of $32 million is expected to be funded from working capital, cash flow and debt. Equity financing may be utilized in the future to accelerate existing projects or to finance new opportunities.

Management's Report

The consolidated financial statements of TransGlobe Energy Corporation were prepared by management within acceptable limits of materiality and are in accordance with Canadian generally accepted accounting principles. Management is responsible for ensuring that the financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

The consolidated financial statements have been prepared by management in accordance with the accounting policies as described in the notes to the consolidated financial statements. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. When necessary, such estimates are based on informed judgements made by management.

Management has designed and maintains an appropriate system of internal controls to provide reasonable assurance that all assets are safeguarded and financial records properly maintained to facilitate the preparation of consolidated financial statements for reporting purposes.

Deloitte & Touche LLP, an independent firm of Chartered Accountants appointed by the shareholders, have conducted an examination of the corporate and accounting records in order to express their opinion on the consolidated financial statements. The Audit Committee, consisting of three independent directors, has met with representatives of Deloitte & Touche LLP and management in order to determine if management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Board of Directors has approved the consolidated financial statements.

Ross G. Clarkson
President &
Chief Executive Officer

David C. Ferguson
Vice President, Finance &
Chief Financial Officer

March 9, 2005

Report of Independent Registered Chartered Accountants

To the Shareholders of **TransGlobe Energy Corporation:**

We have audited the consolidated balance sheets of TransGlobe Energy Corporation as at December 31, 2004 and 2003 and the consolidated statements of income and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. These standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of TransGlobe Energy Corporation as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly we express no such opinion.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Alberta, Canada
February 18, 2005

COMMENTS BY AUDITORS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCES

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph (following the opinion paragraph) when there are changes in accounting principles that have a material effect on the comparability of the Company's financial statements, such as the changes described in Note 2 to the consolidated financial statements. Our report to the board of directors and shareholders on the consolidated financial statements of TransGlobe Energy Corporation dated February 18, 2005, is expressed in accordance with Canadian reporting standards which do not require a reference to such changes in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Alberta, Canada
February 18, 2005

Consolidated Statements of Income and Deficit

(Expressed in thousands of U.S. Dollars)		**Year Ended December 31, 2004**		Year Ended December 31, 2003 (Restated Note 2)
REVENUE				
Oil and gas sales, net of royalties	**$**	**31,630**	$	17,162
Other income		**13**		374
		31,643		17,536
EXPENSES				
Operating		**7,064**		3,706
General and administrative		**1,664**		1,207
Stock-based compensation (Note 8g)		**1,310**		-
Foreign exchange loss		**289**		157
Interest		**56**		1
Depletion, depreciation and accretion		**10,346**		6,253
		20,729		11,324
Income before income taxes		**10,914**		6,212
Income taxes (Note 9)				
- future		**(285)**		(2,448)
- current		**5,280**		2,755
		4,995		307
NET INCOME		**5,919**		5,905
Deficit, beginning of year		**(6,393)**		(12,298)
Retroactive application of changes in accounting policies applied with restatement (Note 2a)		**72**		72
Deficit, beginning of year, as restated		**(6,321)**		(12,226)
Retroactive application of changes in accounting policies applied without restatement (Note 2d)		**(283)**		-
Deficit, end of year	**$**	**(685)**	$	(6,321)
Net income per share (Note 11)				
Basic	**$**	**0.11**	$	0.11
Diluted	**$**	**0.10**	$	0.11

Consolidated Balance Sheets

(Expressed in thousands of U.S. Dollars)	**December 31, 2004**	December 31, 2003
		(Restated Note 2)
ASSETS		
Current		
Cash and cash equivalents	**$ 4,988**	$ 4,452
Accounts receivable	**6,029**	2,383
Oil inventory	**389**	-
Prepaid expenses	**274**	161
	11,680	6,996
Property and equipment		
Republic of Yemen (Note 3)	**26,054**	18,563
Canada (Note 4)	**19,111**	8,470
Arab Republic of Egypt (Note 5)	**992**	-
	46,157	27,033
Future income tax asset (Note 9)	**2,299**	1,572
Deferred financing costs (Note 6)	**386**	-
	$ 60,522	$ 35,601
LIABILITIES		
Current		
Accounts payable and accrued liabilities	**$ 8,841**	$ 4,459
Asset retirement obligations (Note 7)	**902**	467
	9,743	4,926
Commitments and Contingencies (Note 13)		
SHAREHOLDERS' EQUITY		
Share capital (Note 8)	**47,296**	36,996
Contributed surplus (Note 2d)	**1,593**	-
Cumulative translation adjustment (Note 2e)	**2,575**	-
Deficit	**(685)**	(6,321)
	50,779	30,675
	$ 60,522	$ 35,601

APPROVED BY THE BOARD

Ross G. Clarkson, Director

Lloyd W. Herrick, Director

Consolidated Statements of Cash Flows

(Expressed in thousands of U.S. Dollars)	**Year Ended December 31, 2004**	Year Ended Decem ber 31, 2003
		(Restated Note 2)
CASH FLOWS RELATED TO THE FOLLOWING ACTIVITIES:		
OPERATING		
Net income	**$ 5,919**	$ 5,905
Adjustments for:		
Depletion, depreciation and accretion	**10,346**	6,253
Gain on sale of property and equipment	**-**	(363)
Amortization of deferred financing costs (Note 6)	**35**	-
Future income taxes	**(285)**	(2,448)
Stock-based compensation	**1,310**	-
Cash flow from operations	**17,325**	9,347
Changes in non-cash working capital (Note 10)	**(4,259)**	3,117
	13,066	12,464
FINANCING		
Issue of share capital (Note 8)	**10,006**	2,270
Repurchase of share capital	**-**	(41)
Deferred financing costs (Note 6)	**(421)**	-
Changes in non-cash working capital (Note 10)	**24**	-
	9,609	2,229
INVESTING		
Exploration and development expenditures		
Republic of Yemen	**(15,275)**	(9,012)
Canada	**(10,100)**	(5,217)
Arab Republic of Egypt	**(992)**	-
Proceeds on disposal of property and equipment	**-**	442
Changes in non-cash working capital (Note 10)	**4,678**	951
	(21,689)	(12,836)
Effect of exchange rate changes on cash and cash equivalents	**(450)**	-
NET INCREASE IN CASH AND CASH EQUIVALENTS	**536**	1,857
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**4,452**	2,595
CASH AND CASH EQUIVALENTS, END OF YEAR	**$ 4,988**	$ 4,452

Notes to the Consolidated Financial Statements

Years Ended December 31, 2004 and December 31, 2003
(Expressed in U.S. Dollars, unless otherwise stated)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Consolidated Financial Statements include the accounts of TransGlobe Energy Corporation and subsidiaries ("TransGlobe" or the "Company"), and are presented in accordance with Canadian generally accepted accounting principles (information prepared in accordance with generally accepted accounting principles in the United States is included in Note 15). In these Consolidated Financial Statements, unless otherwise indicated, all dollar amounts are expressed in United States (U.S.) dollars. All references to US$ or to $ are to United States dollars and references to C$ are to Canadian dollars.

Nature of Business and Principles of Consolidation

The Company is engaged primarily in oil and gas exploration, development and production and the acquisition of properties. Such activities are concentrated in three geographic areas:

- Block 32 and Block S-1 within the Republic of Yemen;
- Nuqra Block 1 within the Arab Republic of Egypt; and
- the Western Canadian Sedimentary Basin within Canada.

Joint Ventures

Investments in unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby the Company's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Currency Translation

The accounts of the self-sustaining Canadian operations are translated using the current rate method, whereby assets and liabilities are translated at year end exchange rates, while revenues and expenses are translated using average annual rates. Translation gains and losses relating to the self-sustaining Canadian operations are included as a separate component of shareholders' equity.

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statements of Income and Deficit.

Measurement Uncertainty

Timely preparation of the financial statements in conformity with Canadian generally accepted accounting principles requires that Management make estimates and assumptions and use judgment regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and amortization, asset retirement costs and obligations, future income taxes, and amounts used for ceiling test and impairment calculations are based on estimates of oil and natural gas reserves and future costs required to develop those reserves. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

Revenue Recognition

Revenues associated with the sales of the Company's crude oil, natural gas and natural gas liquids owned by the Company are recognized when title passes from the Company to its customer. Crude oil and natural gas produced and sold by the Company below or above its working interest share in the related resource properties results in production underliftings or overliftings. Underliftings are recorded as inventory and overliftings are recorded as deferred revenue.

Income Taxes

The Company records income taxes using the liability method. Under this method, future income tax assets and liabilities are measured using the substantively enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

Flow Through Shares

The Company has financed a portion of its exploration and development activities in Canada through the issue of flow through shares. Under the terms of these share issues, the tax attributes of the related expenditures are renounced to subscribers. To recognize the foregone tax benefits, share capital is reduced and a future income tax liability is recorded for the income tax amount related to the renounced deductions.

Per Share Amounts

Basic net income per share is calculated using the weighted average number of shares outstanding during the year. Diluted net income per share is calculated by giving effect to the potential dilution that would occur if stock options were exercised. Diluted net income per share is calculated using the treasury stock method. The treasury stock method assumes that the proceeds received from the exercise of "in-the-money" stock options are used to repurchase common shares at the average market price.

Cash and Cash Equivalents

Cash includes actual cash held and short-term investments such as treasury bills with original maturity of less than three months.

Inventories

Product inventories are valued at the lower of average cost and net realizable value on a first-in, first-out basis.

Property and Equipment

The Company follows the full cost method of accounting for oil and gas operations whereby all costs associated with the exploration for and development of oil and gas reserves are capitalized on a country-by-country basis. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells, production equipment and overhead charges directly related to acquisition, exploration and development activities.

Capitalized costs within each country are depleted and depreciated on the unit-of-production method based on the estimated gross proved reserves and determined by independent petroleum engineers. Oil and gas reserves and production are converted into equivalent units of 6,000 cubic feet of natural gas to one barrel of oil. Depletion and depreciation is calculated using the capitalized costs, including estimated asset retirement costs, plus the estimated future costs to be incurred in developing proved reserves, net of estimated salvage value.

Costs of acquiring and evaluating unproved properties and major development projects are initially excluded from the depletion and depreciation calculation until it is determined whether or not proved reserves can be assigned to such properties. Costs of unproved properties and major development projects are transferred to depletable costs based on the percentage of reserves assigned to each project over the expected total reserves when the project was initiated. These costs are assessed periodically to ascertain whether impairment has occurred.

Proceeds from the sale of oil and gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would alter the rate of depletion and depreciation by more than 20 percent in a particular country, in which case a gain or loss on disposal is recorded.

An impairment loss is recognized in net income if the carrying amount of a country (cost centre) is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than carrying amount, the impairment is the amount by which the carrying amount exceeds the sum of:

i. the fair value of proved plus probable reserves; and
ii. the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves.

Furniture and fixtures are depreciated at declining balance rates of 20 to 30 percent.

Capitalization of Costs

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred.

Amortization of Deferred Financing Costs

Deferred financing costs are charged to expense over the term of the related loan facility.

Asset Retirement Obligations

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when the liability is incurred. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites. The asset retirement cost, equal to the estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Asset retirement costs for natural gas and crude oil assets are amortized using the unit-of-production method.

Amortization of asset retirement costs are included in depreciation, depletion and accretion on the Consolidated Statements of Income and Deficit. Increases in the asset retirement obligation resulting from the passage of time are recorded as depletion, depreciation and accretion in the Consolidated Statements of Income and Deficit. Actual expenditures incurred are charged against the accumulated obligation.

Stock-based Compensation

The Company records compensation expense in the Consolidated Financial Statements for stock options granted to employees and directors using the fair value method. Fair values are determined using the Black-Scholes option pricing model. Compensation costs are recognized over the vesting period.

2. CHANGES IN ACCOUNTING POLICIES AND PRACTICES

a) Asset Retirement Obligations

Effective January 1, 2004 the Company retroactively adopted the Canadian Institute of Chartered Accountants ("CICA") section 3110, "Asset Retirement Obligations". The new recommendations require the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion expense which is included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset.

The Company previously estimated future site restoration costs based on current regulations, costs, technology and industry standards. The costs were recorded into income using the unit-of-production method and accumulated a liability on the Consolidated Balance Sheet. Upon adoption, all prior periods have been restated for the change in accounting policy. The impact was as follows:

Consolidated Balance Sheet - as at December 31, 2003

(000's)	As Reported	Change	As Restated
Assets			
Net property and equipment	$ 26,646	$ 387	$ 27,033
Liabilities and shareholders' equity			
Asset retirement obligations	-	467	467
Provision for site restoration and abandonment	153	(153)	-
Deficit	(6,393)	72	(6,321)

Consolidated Statements of Income and Deficit

	Year ended December 31, 2003		
(000's)	As Reported	Change	As Restated
Depletion, depreciation and accretion	$ 6,253	$ -	$ 6,253
Net income	5,905	-	5,905

b) Property and Equipment

Effective January 1, 2004 the Company adopted Accounting Guideline 16, "Oil and Gas Accounting - Full Cost" ("AcG-16"), which replaces Accounting Guideline 5, "Full Cost Accounting in the Oil and Gas Industry". AcG-16 modifies how the ceiling test is performed and is consistent with CICA section 3063, "Impairment of Long-lived Assets". The recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value. This approach incorporates risks and uncertainties in the expected future cash flows which are discounted using a risk free rate. The adoption of AcG-16 had no effect on the Company's financial results.

c) Impairment of Long-lived Assets

Effective January 1, 2004 the Company adopted CICA section 3063, "Impairment of Long-lived Assets", which had no effect on the consolidated financial statements.

d) Stock-based Compensation

Effective January 1, 2004 the Company adopted the new accounting standard of CICA section 3870, "Stock-based Compensation and Other Stock-based Payments", retroactively without restatement of prior periods. This Canadian accounting standard requires the Company to record a compensation expense over the vesting period based on the fair value of options granted to employees and directors since January 1, 2002.

This change resulted in an increase to opening deficit of $283,000, an increase to contributed surplus of $283,000 and a non-cash expense of $1,310,000 in 2004.

e) Currency Translation

As a result of the increase in cash flow from Canadian operations, the Company reviewed its accounting practices for operations in Canada and determined that such operations are self-sustaining. The accounts of the self-sustaining Canadian operations are translated using the current rate method, whereby assets and liabilities are translated at period-end exchange rates, while revenues and expenses are translated using average rates for the period. Translation gains and losses relating to the operations are deferred and included as a separate component of shareholders' equity.

Previously, Canadian operations were considered to be integrated and were translated using the temporal method. Under the temporal method, monetary assets and liabilities were translated at the period end exchange rate, other assets and liabilities at the historical rates and revenues and expenses at the average monthly rates except depreciation, depletion and amortization, which were translated on the same basis as the related assets.

This change in accounting practice was adopted prospectively beginning October 1, 2004 and resulted in an increase in property and equipment of $1,885,000, future income tax asset of $43,000 and an increase in the asset retirement obligation of $87,000, all of which resulted in a net operating foreign currency translation adjustment of $1,841,000. For the period from October 1, 2004 to December 31, 2004, the translation gain was $734,000 which was recorded to the foreign currency translation adjustment account.

f) Accounting for Derivate Instruments and Hedging Activities

The Canadian Institute of Chartered Accountants ("CICA") modified Accounting Guideline 13 ("AcG 13") "Hedging Relationships", effective January 1, 2004, to clarify circumstances in which hedge accounting is appropriate. In addition, the CICA simultaneously amended EIC 128, "Accounting for Trading, Speculative or Non Trading Derivative Financial Instruments" to require that all derivative instruments that do not qualify as a hedge under AcG 13, or are not designated as a hedge, be recorded in the balance sheet as either an asset or liability with changes in fair value recognized in earnings. If a derivative financial instrument qualifies as a hedge under AcG 13 then the change in fair value of the financial instrument is recognized in earnings in the same period as the hedged item. AcG-13 has essentially the same criteria to be satisfied before the application of hedge accounting is permitted as the corresponding requirements of the Financial Accounting Standards Board ("FASB") Statement No. 133. "Accounting for Derivative Instruments and Hedging Activities"("FAS 133").

The adoption of AcG-13 had no effect on the Company's financial results.

3. PROPERTY AND EQUIPMENT - REPUBLIC OF YEMEN

(000's)	**2004**	2003
Oil and gas properties		
- Block 32	**$ 21,651**	$ 17,954
- Block S-1	**24,782**	12,650
- Other	**115**	82
Accumulated depletion and depreciation	**(20,494)**	(12,123)
	$ 26,054	$ 18,563

The Company commenced production on Block 32 in November 2000. The Production Sharing Agreement ("PSA") continues to 2020, with provision for a five year extension. The Yemen Ministry of Oil and Minerals approved the Development Plan and Development Area for the Block S-1 PSA in October 2003 which will have a 20 year term with provision for a five year extension. Major development project costs in the amount of $Nil in 2004 ($11,684,000 - 2003) were excluded from costs subject to depletion and depreciation representing a portion of the costs incurred in Block S-1. During the year the Company capitalized overhead costs relating to exploration and development activities of $301,000 (2003 - $240,000).

Block 32 (13.81087% working interest)

The PSA provides for the Ministry of Oil and Mineral Resources ("MOM") in the Republic of Yemen to receive a royalty of 3% (10% over 25,000 barrels of oil per day ("Bopd")) of gross production with the remaining 97% of production split between cost recovery oil and production sharing oil. Cost recovery oil is up to a maximum of 60% of 97% of the production limited to operating costs and allocated recoverable exploration and development expenditures as outlined in the PSA. Cost recovery oil is 100% for the account of the Block 32 Contractor (Joint Venture Partners) to recover operating costs and exploration and development expenditures. The remaining production sharing oil is shared 65% by MOM and 35% by the Block 32 Contractor which is further shared 5% Yemen Oil Company ("YOC")/95% Block 32 Contractor. These terms remain in place as long as proved recoverable reserves do not exceed 30 million barrels of oil (gross) or production of 25,000 Bopd.

Block S-1 (25% working interest)

The PSA provides MOM with a sliding scale royalty of 3%-10% based on daily oil production between 0-100,000 Bopd with the remaining production split between cost recovery oil and production sharing oil. Cost recovery oil is up to a maximum of 50% of after royalty production limited to operating costs and allocated recoverable exploration and development expenditures, as outlined in the PSA, to be utilized 100% by the Block S-1 Contractor. The balance of the revenue is allocated to production sharing oil and is shared 65%-80% by MOM and 35%-20% by the Block S-1 Contractor (which is further shared 17.5% YOC/82.5% Block S-1 Contractor) based on the production level.

4. PROPERTY AND EQUIPMENT - CANADA

(000's)		**2004**		2003
Oil and gas properties	**$**	**23,444**	$	10,127
Furniture and fixtures		**366**		250
Accumulated depletion and depreciation		**(4,699)**		(1,907)
	$	**19,111**	$	8,470

During the year the Company capitalized overhead costs relating to exploration and development activities of $278,000 (2003 - $206,000).

5. PROPERTY AND EQUIPMENT - ARAB REPUBLIC OF EGYPT

(000's)		**2004**		2003
Oil and gas properties	$	**989**	$	-
Furniture and fixtures		**3**		-
	$	**992**	$	-

The Company capitalized general and administrative costs relating to the start-up of TransGlobe Petroleum Egypt Inc. of $448,000 (2003 - $Nil). The remaining costs related to geological and geophysical activity.

6. LONG-TERM DEBT

The Company has a $7,000,000 loan facility which expires May 2006. The loan facility bears interest at the Eurodollar Rate plus four percent and is secured by a first floating charge debenture over all assets of the Company, a general assignment of book debts and certain covenants, among other things. At December 31, 2004 $Nil (2003 - $Nil) was drawn on these loan facilities.

During the year the Company spent $421,000 to secure the new loan facility, of which $35,000 has been amortized to the income statement and $386,000 has been deferred and will be amortized to income over the initial term of the loan facility.

7. ASSET RETIREMENT OBLIGATIONS

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas properties:

(000's)		**2004**		2003
Asset retirement obligations, beginning of year	**$**	**467**	$	250
Liabilities incurred during period		**274**		200
Liabilities settled during period		**-**		-
Accretion		**34**		17
Foreign exchange loss		**127**		-
Asset retirement obligations, end of year	**$**	**902**	$	467

At December 31, 2004, the estimated total undiscounted amount required to settle the asset retirement obligations was $1,331,000 (2003 - $792,000). These obligations will be settled at the end of the useful lives of the underlying assets, which currently extend up to 10 years into the future. This amount has been discounted using a credit-adjusted risk-free interest rate of 6.5%.

8. SHARE CAPITAL

a) Authorized

The Company is authorized to issue an unlimited number of common shares with no par value.

b) Issued

(000's)	Number of shares		**Amount**
Balance, December 31, 2002	51,495	**$**	**35,643**
Exercise of stock options (f)	985		**217**
Repurchase of share capital (c)	(100)		**(41)**
Private placement net of issue costs (d)	1,363		**2,053**
Future tax effect of flow through shares (d)	-		**(876)**
Balance, December 31, 2003	53,743		**36,996**
Exercise of stock options (f)	523		**164**
Bought deal financing net of issue costs (e)	2,530		**8,557**
Bought deal financing over-allotment net of issue costs (e)	380		**1,285**
Future tax effect of bought deal financing costs (e)	-		**294**
Balance, December 31, 2004	57,176	**$**	**47,296**

c) In March 2003, the Company repurchased 100,000 shares at C$0.60 and cancelled the shares pursuant to a normal course issuer bid approved in December 2002. The normal course issuer bid terminated December 8, 2003.

d) In December 2003, the Company issued 1,363,637 flow through common shares in a private placement at C$2.20 per share for net proceeds of US$2,053,005. Insiders of the Company subscribed for 65,000 shares. The terms of the flow through shares provide that the Company renounce Canadian tax deductions in the amount of C$3,000,001 to the subscribers with the entire amount to be expended by the Company by December 31, 2004. As described in Note 1, share capital is reduced and future income taxes are increased by the estimated amount of the future income taxes payable by the Company ($875,775) as a result of renouncing the expenditures to subscribers.

e) In November 2004, the Company issued 2,530,000 common shares in a bought deal financing at C$4.35 per share for net proceeds of US$8,557,000. In December 2004, the Company issued an additional 379,500 shares as part of the over-allotment of the bought deal financing in November 2004 at C$4.35 per share for net proceeds of US$1,285,000. The issue costs were $848,686 for the bought deal financing and over-allotment. Share capital is increased and future income tax asset increased by the estimated future income taxes recoverable by the Company for the share issue expenses.

f) Stock Options

The Company adopted a new stock option plan in May 2004 (the "Plan"). The maximum number of common shares to be issued upon the exercise of options granted under the Plan is 5,718,000 common shares. All incentive stock options granted under the Plan have a per-share exercise price not less than the trading market value of the common shares at the date of grant and vest as to 50% of the options, six months after the grant date, and as to the remaining 50%, one year from the grant date. Effective February 1, 2005, all new grants of stock options will vest one-third on each of the first, second and third anniversaries of the grant date.

	2004		2003	
(000's except per share amounts)	**Number of Options**	**Weighted-Average Exercise Price**	Number of Options	Weighted-Average Exercise Price
Options outstanding at beginning of year	**2,760**	**$ 0.36**	3,625	$ 0.32
Granted	**1,225**	**$ 2.57**	120	$ 0.47
Exercised	**(523)**	**$ 0.28**	(985)	$ 0.22
Expired	**-**	**-**	-	-
Options outstanding at end of year	**3,462**	**$ 1.15**	2,760	$ 0.36
Options exercisable at end of year	**2,787**	**$ 0.79**	2,640	$ 0.36

The following table summarizes information about the stock options outstanding at December 31, 2004:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number Out-standing at Dec.31, 2004 (000's)	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at Dec. 31, 2004 (000's)	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price
C$0.73	667	0.6	C$0.73	667	0.6	C$0.73
C$0.55	200	1.4	C$0.55	200	1.4	C$0.55
C$0.39	40	1.8	C$0.39	40	1.8	C$0.39
C$0.50	1,260	2.3	C$0.50	1,260	2.3	C$0.50
C$0.63	70	3.5	C$0.63	70	3.5	C$0.63
C$3.40	150	4.0	C$3.40	75	4.0	C$3.40
C$3.26	870	4.2	C$3.26	435	4.2	C$3.26
C$3.43	80	4.3	C$3.43	40	4.3	C$3.43
US$3.25	100	4.7	US$3.25	-	-	-
C$4.50	25	4.9	C$4.50	-	-	-
	3,462	2.6	US$1.15	2,787	2.2	US$0.79

g) Stock-based Compensation

Effective January 1, 2004 and as described in Note 2, the Company adopted CICA section 3870 retroactively without restatement whereby the fair value of all stock options granted after January 1, 2002 are estimated on the date of grant using the Black-Scholes option-pricing model. Compensation expense of $1,310,000 has been recorded in the Consolidated Statements of Income and Deficit in 2004 (2003 - $Nil). If the Company would have adopted CICA section 3870 retroactively with restatement, net income would have decreased $143,000 in 2003 to $5,762,000 and net income per share basic and diluted would be unchanged. The weighted average fair market value of stock options granted during the year and assumptions used in their determination are as noted below:

	2004	2003
Weighted average fair market value per option (Cdn$)	**1.84**	0.19
Risk free interest rate (%)	**5.17**	5.40
Expected lives (years)	**4.00**	2.50
Expected volatility (%)	**66.37**	97.01
Dividend per share	**0.00**	0.00

Prior to January 1, 2004 the Company accounted for its stock-based compensation plan using the intrinsic-value of the options granted whereby no costs have been recognized in the financial statements for stock options granted to employees and directors at the date of grant.

9. INCOME TAXES

The Company's future Canadian income tax assets are as follows:

(000's)		2004		2003
Temporary differences related to:				
Oil and gas properties	**$**	**2,154**	$	2,142
Non-capital losses carried forward		**457**		965
Share issue expenses		**287**		107
Valuation allowance		**(599)**		(1,642)
	$	**2,299**	$	1,572

The Company has deductible temporary differences of C$1,520,000 related to non-capital losses carried forward and C$7,344,000 related to income tax pools in excess of the carrying value of the Company's Canadian property and equipment. The Company also has $12,700,000 of income tax losses in the United States of America. The Canadian losses carried forward expire between 2007 and 2009 and the United States of America losses carried forward expire between 2006 and 2020. In total, these temporary differences would generate a future income tax asset of C$3,483,000 on Canadian operations. A valuation allowance of C$720,000 has been recorded to reduce this amount to the amount which is considered to be more likely than not to be recovered.

Current income taxes in the amount of $5,280,000 (2003 - $2,755,000) represents income taxes of $5,269,000 incurred and paid under the laws of the Republic of Yemen pursuant to the PSA on Block 32 and Block S-1 and $11,000 paid in Canada.

The provision for income taxes has been computed as follows:

(000's)		2004		2003
Computed Canadian expected income tax expense at 38.87% (2003 - 40.62%)	**$**	**4,301**	$	2,523
Non-deductible Crown charges (net of ARTC)		**261**		96
Resource allowance		**(180)**		(62)
Non-deductible stock-based compensation expense		**509**		-
Different tax rates in the Republic of Yemen		**945**		328
Future income tax assets not previously recognized		**(1,083)**		(2,448)
Other differences		**242**		(130)
	$	**4,995**	$	307

10. SUPPLEMENTAL CASH FLOW INFORMATION

(000's)		**2004**		2003
Operating activities				
Decrease (increase) in current assets				
Accounts receivable	**$**	**(3,896)**	$	1,335
Prepaid expenses		**(113)**		(72)
Oil inventory		**(180)**		-
Increase (decrease) in current liabilities				
Accounts payable		**(70)**		1,854
	$	**(4,259)**	$	3,117
Investing activities				
Decrease (increase) in current assets				
Accounts receivable	**$**	**250**	$	(735)
Increase (decrease) in current liabilities				
Accounts payable		**4,428**		1,686
	$	**4,678**	$	951
Financing activities				
Increase (decrease) in current liabilities				
Accounts payable	**$**	**24**	$	-
	$	**24**	$	-
Interest paid	**$**	**56**	$	1
Taxes paid	**$**	**5,280**	$	2,755

11. NET INCOME PER SHARE

In calculating the net income per share basic and diluted, the following weighted average shares were used:

(000's)	**2004**	2003
Weighted average number of shares outstanding	**54,388**	52,071
Shares issuable pursuant to stock options	**3,445**	3,066
Shares to be purchased from proceeds of stock options under treasury stock method	**(1,114)**	(1,358)
Weighted average number of diluted shares outstanding	**56,719**	53,779

The treasury stock method assumes that the proceeds received from the exercise of "in-the-money" stock options are used to repurchase common shares at the average market price. In calculating the weighted average number of diluted common shares outstanding for the year ended December 31, 2004, we excluded 125,000 options (2003 - nil) because their exercise price was greater than the annual average common share market price in this period.

12. SEGMENTED INFORMATION

In 2004 the Company had oil and natural gas production in two geographic segments, the Republic of Yemen and Canada, and start-up operations in a third geographic segment, the Arab Republic of Egypt. The property and equipment in each geographic segment are disclosed in Notes 3, 4 and 5.

The results of operations for the year ended December 31, 2004 are comprised of the following:

(000's)	**Republic of Yemen**	**Canada**	**Total**
REVENUE			
Oil and gas sales, net of royalties	**$ 24,966**	**$ 6,664**	**$ 31,630**
EXPENSES			
Operating	**5,449**	**1,615**	**7,064**
Depletion, depreciation and accretion	**8,162**	**2,184**	**10,346**
Segmented operations	**$ 11,355**	**$ 2,865**	**14,220**
Other income			**13**
			14,233
General and administrative			**1,664**
Stock-based compensation			**1,310**
Foreign exchange loss			**289**
Interest			**56**
Income taxes (Note 9)			**4,995**
NET INCOME			**$ 5,919**

In the Republic of Yemen, the Company sold all of its 2004 Block 32 production to one purchaser and all of its 2004 Block S-1 production to another single purchaser. In Canada, the Company sold primarily all of its 2004 gas production to one purchaser and primarily all of its 2004 oil production to another single purchaser.

The results of operations for the year ended December 31, 2003 are comprised of the following:

(000's)	Republic of Yemen	Canada	Total
REVENUE			
Oil and gas sales, net of royalties	$ 14,625	$ 2,537	$ 17,162
EXPENSES			
Operating	3,012	694	3,706
Depletion, depreciation and accretion	5,516	737	6,253
Segmented operations	$ 6,097	$ 1,106	7,203
Other income (includes a gain on sale of property and equipment in the United States of America of $363,000)			374
			7,577
General and administrative			1,207
Foreign exchange loss			157
Interest			1
Income taxes (Note 9)			307
NET INCOME			$ 5,905

In the Republic of Yemen, the Company sold all of its 2003 production to one purchaser. In Canada, the Company sold primarily all of its 2003 gas production to one purchaser and primarily all of its 2003 oil production to another single purchaser.

13. COMMITMENTS AND CONTINGENCIES

The Company is committed to office and equipment leases over the next five years as follows:

2005	$ 191,000
2006	243,000
2007	235,000
2008	328,000
2009	348,000

In 2004, the Company entered into a one year fixed price contract to sell 10,000 barrels of oil per month in Block 32, Yemen commencing July 1, 2004 at $33.90 per barrel for Dated Brent plus or minus the Yemen Government's official selling price differential.

Upon the determination that proved recoverable reserves are 40 million barrels or greater for Block S-1, Yemen, the Company will be required to pay a finders' fee to third parties in the amount of $281,000.

Pursuant to the Company's farm-in agreement on the Nuqra Concession in Egypt, the Company is committed to spend $6 million over the next 5 years to earn its 50% working interest. As part of this commitment the Company issued a $2 million letter of credit on July 8, 2004 to Ganoub El Wadi Holding Petroleum Company which expires on February 14, 2007. This letter of credit is secured by a guarantee granted by Export Development Canada.

14. FINANCIAL INSTRUMENTS

Carrying values of financial instruments, which include cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities approximate their fair value due to the short-term nature of these amounts.

The Company has foreign exchange risk due to the fact that it operates using other than United States currency. The Company has commodity price risk associated with its sale of crude oil and natural gas.

The majority of the accounts receivable are in respect of oil and gas operations. The Company generally extends unsecured credit to these customers and therefore the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes the risk is mitigated by the size and reputation of the companies to which they extend credit. The Company has not experienced any material credit loss in the collection of accounts receivable to date.

15. DIFFERENCES BETWEEN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN CANADA AND THE UNITED STATES OF AMERICA

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP or Cdn. GAAP) which differ in certain material respects from those principles that the Company would have followed had its consolidated financial statements been prepared in accordance with United States of America generally accepted accounting principles (U.S. GAAP).

a) Full Cost Accounting

The full cost method accounting for crude oil and natural gas operations under Canadian and U.S. GAAP differ in the following respect. Under U.S. GAAP, a ceiling test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum of the present value, discounted at 10%, of the estimated unescalated future net operating revenue from proved reserves plus unimpaired unproved property costs less future development costs, related production costs and applicable taxes. Under Canadian GAAP, a similar ceiling test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize forecasted pricing to determine whether impairment exists. However, in Canada, the impaired amount is measured using the fair value of reserves.

There are no impairment charges under Canadian GAAP or U.S. GAAP.

b) Stock-based Compensation

The Company has a stock-based compensation plan as more fully described in Note 8. Under Canadian GAAP, compensation costs have been recognized in the financial statements for stock options granted to employees and directors since January 1, 2002. For U.S. GAAP, the Company uses the intrinsic value method of accounting for stock options granted to employees and directors whereby no costs are recognised in the financial statements, per APB opinion No. 25 as interpreted by FASB Interpretation No. 44.

The effect of applying this provision to the Company's U.S. GAAP financial statements results in a decrease to stock-based compensation in 2004 by $1,310,000 and a corresponding decrease to the contributed surplus account. Also, the deficit would decrease by $283,000 in 2004 with a corresponding decrease to the contributed surplus account relating to the 2004 adoption entry for Canadian GAAP that is not required for U.S. GAAP.

Had compensation expense been determined based on fair value at the grant dates for the stock options grants consistent with the method under SFAS No. 123, the pro forma effect on the Company's net income under U.S. GAAP would be as follows:

(000's except per share amounts)	**2004**	2003
Compensation costs	**$ 1,310**	$ 143
Net Income (U.S. GAAP)		
As reported	**$ 7,229**	$ 5,101
Pro forma	**$ 5,919**	$ 4,958
Net Income per share (U.S. GAAP)		
As reported		
- basic	**$ 0.13**	$ 0.10
- diluted	**$ 0.13**	$ 0.09
Pro forma		
- basic	**$ 0.11**	$ 0.09
- diluted	**$ 0.10**	$ 0.09

c) Future Income Taxes

The Company records the renouncement of tax deductions related to flow through shares by reducing share capital and recording a future tax liability in the amount of the estimated cost of the tax deductions flowed to the shareholders. U.S. GAAP requires that the share capital on flow through shares be stated at the quoted market value of the shares at the date of issuance. In addition, the temporary difference that arises as a result of the renouncement of the deductions, less any proceeds received in excess of the quoted market value of the shares is recognized in the determination of income tax expense for the period. The effect of applying this provision to the Company's financial statements would result in an increase in income tax expense and future tax liability by $Nil in 2004, $876,000 in 2003, $67,000 in 2002 and $335,000 in 2000 representing the tax effect of the flow through shares and a corresponding increase to share capital and decrease to future tax liability by $Nil in 2004, $876,000 in 2003, $67,000 in 2002 and $335,000 in 2000 to record the recognition of the benefit of tax losses available to the Company equal to the liability arising from renouncing tax pools to the subscribers.

Under U.S. GAPP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted tax rates. The effect of this change between Canadian and U.S. GAAP would result in an increase in future income tax expense and future tax liability of $231,000 in 2004, $592,000 in 2003 and $Nil in 2002 representing the higher enacted tax rates over the substantively enacted tax rates and a corresponding reduction in future income tax expense and future tax liability of $231,000 in 2004, $592,000 in 2003 and $Nil in 2002 to record an additional valuation allowance against the increased tax asset.

d) Foreign Currency Translation Adjustments and Other Comprehensive Income

U.S. GAAP requires gains or losses arising from the translation of self-sustaining operations to be included in other comprehensive income. Canadian GAAP requires these amounts to be recorded in a separate component of Shareholders' Equity. Other comprehensive income arose from the translation adjustment resulting from the translation of Canadian currency financial statements into U.S. dollars under FAS 52. At December 31, 2004, accumulated other comprehensive income related to these items was a gain of $2,575,000 of which $1,841,000 represents the translation adjustment resulting from the Canadian operations becoming a self-sustaining operation effective October 1, 2004.

e) Asset Retirement Obligation

The Company adopted the Canadian accounting standard for asset retirement obligations, as outlined in the CICA section 3110. This standard is equivalent to U.S. FAS 143, Accounting for Asset Retirement Obligations, which was effective for fiscal periods beginning on or after January 1, 2003. The Company adopted the Canadian standard effective January 1, 2004 which eliminated the U.S. GAAP reconciling item in respect to accounting for the obligation, however a difference is created on how the transition amounts are disclosed.

For US GAAP, FAS 143 was adopted January 1, 2003 and required the cumulative impact of the change in accounting policy to be presented in the 2003 Income Statement and that prior periods not be restated prior to 2003. For Canadian GAAP, all prior periods were restated. The effect of applying the different transition provision to the Company's consolidated financial statements would result in net income under U.S. GAAP in 2003 being reduced by $72,000 for the cumulative effect of the change in accounting policy and no opening deficit adjustment in 2003.

f) Escrowed Shares

For U.S. GAAP purposes, escrowed shares would be considered a separate compensatory arrangement between the Company and the holder of the shares. Accordingly, the fair market value of shares at the time the shares are released from escrow will be recognized as a charge to income in that year with a corresponding increase in share capital. The difference in share capital between Canadian GAAP and U.S. GAAP represents the effect of applying this provision in 1995 when 188,000 escrow shares were released resulting in an increase in share capital of $833,000 with the offset to deficit.

g) Cash Flows

Under Canadian GAAP, reporting entities are permitted to present a sub-total prior to changes in non-cash working capital within operating activities. This information is perceived to be useful information for various users of the financial statements and is commonly presented by Canadian public companies. Under U.S. GAAP, this sub-total is not permitted to be shown and would be removed in the statements of cash flows for all periods presented.

h) Consolidated Balance Sheets

Had the Company followed US GAAP, asset and liability sections of the balance sheet would not have changed from Canadian GAAP to U.S. GAAP.

Had the Company followed U.S. GAAP, the shareholders' equity would have been reported as follows:

	2004		2003	
(000's)	**Cdn. GAAP**	**U.S. GAAP**	Cdn. GAAP	U.S. GAAP
Share capital (c, f)	**$ 47,296**	**$ 49,407**	$ 36,996	$ 39,107
Contributed surplus (b)	**1,593**	**-**	-	-
Cumulative translation adjustment (d)	**2,575**	**-**	-	-
Accumulated other comprehensive income (d)	**-**	**2,575**	-	-
Deficit (b, c, f)	**(685)**	**(1,203)**	(6,321)	(8,432)
	$ 50,779	**$ 50,779**	$ 30,675	$ 30,675

The reconciling items between share capital and deficit for Canadian and United States of America GAAP are $833,000 related to escrowed shares and $1,278,000 related to flow through shares. The reconciling items between contributed surplus and deficit for Canadian and U.S. GAAP are $283,000 for the adoption of stock-based compensation under Canadian GAAP and $1,310,000 for the 2004 stock-based compensation expense under Canadian GAAP, which is not expensed under U.S. GAAP APB Opinion No. 25 as interpreted by FASB Interpretation No. 44.

i) Consolidated Statements of Income and Deficit

Had the Company followed U.S. GAAP, the statement of income would have been reported as follows:

(000's, except per share amounts)		**2004**		2003
Net income for the year under Canadian GAAP	**$**	**5,919**	$	5,905
Adjustments, before income taxes:				
Stock-based compensation (b)		**1,310**		-
Future income tax expense (c)		**-**		(876)
Net income before change in accounting policy - U.S. GAAP		**7,229**		5,029
Cumulative effect of change in accounting policy - U.S. GAAP (e)		**-**		72
Net income U.S. GAAP		**7,229**		5,101
Deficit, beginning of year - U.S. GAAP		**(8,432)**		(13,533)
Deficit, end of year - U.S. GAAP	**$**	**(1,203)**	$	(8,432)
Net income per share under U.S. GAAP				
- Basic	**$**	**0.13**	$	0.10
- Diluted	**$**	**0.13**	$	0.09

j) Statement of Other Comprehensive Income

(000's)		**2004**		2003
Net income - U.S. GAAP	**$**	**7,229**	$	5,101
Currency translation adjustment (d)		**734**		-
Other comprehensive income	**$**	**7,963**	$	5,101

k) Recent Accounting Pronouncements

In November 2004, the Financial Accounting Standards Board (FASB) issued Statement 151, Inventory Costs. This statement amends ARB 43 to clarify that:

- abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage) should be recognized as current-period charges; and

- requires the allocation of fixed production overhead to inventory based on the normal capacity of the production facilities.

The provisions of this statement are effective for inventory costs incurred during fiscal years beginning after June 15, 2005. We do not expect the adoption of this statement will have any material impact on our results of operations or financial position.

In December 2004, the FASB issued Statement 123(R), Share-Based Payments. This statement revises Statement 123, Accounting for Stock-Based Compensation, and supersedes APB Opinion 25, Accounting for Stock Issued to Employees.

Statement 123(R) requires all stock-based awards issued to employees to be measured at fair value and to be expensed in the income statement. This statement is effective for reporting periods beginning after June 15, 2005.

We are currently expensing stock options issued to employees and directors using the intrinsic value method for U.S. GAAP. Adoption of the fair value method under FASB Statement 123(R) will have an undertermined effect on our results of operations and financial position.

In December 2004, the FASB issued Statement 153, Exchanges of Nonmonetary Assets, an amendment of APB Opinion 29, Accounting for Nonmonetary Transactions. This amendment eliminates the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. Under Statement 153, if a nonmonetary exchange of similar productive assets meets a commercial-substance criterion and fair value is determinable, the transaction must be accounted for at fair value resulting in recognition of any gain or loss. This statement is effective for nonmonetary transactions in fiscal periods that begin after June 15, 2005. The adoption of this statement will not have any material impact on our results of operation or financial position.

CORPORATE INFORMATION

OFFICERS AND DIRECTORS

Robert A. Halpin[1,2,3]
Director, Chairman of the Board

Ross G. Clarkson
Director, President & CEO

Lloyd W. Herrick[2]
Director, Vice President & COO

Erwin L. Noyes[2,3,4]
Director

Geoffrey C. Chase[1,2,4]
Director

Fred J. Dyment[1,3,4]
Director

David C. Ferguson
Vice President, Finance, CFO & Secretary

Edward Bell
Vice President, Exploration

1 Audit Committee
2 Reserves Committee
3 Compensation Committee
4 Governance and Nominating Committee.

STOCK EXCHANGE LISTINGS

TSX:	TGL
AMEX:	TGA

TRANSFER AGENT & REGISTRAR

Computershare Trust Company of Canada
Calgary, Toronto, Vancouver

LEGAL COUNSEL

Burnet, Duckworth & Palmer
Calgary, Alberta

BANKER

Standard Bank London Limited
London, England

AUDITOR

Deloitte & Touche LLP
Calgary, Alberta

EVALUATION ENGINEERS

DeGolyer & MacNaughton Canada Limited
Calgary, Alberta

EXECUTIVE OFFICES

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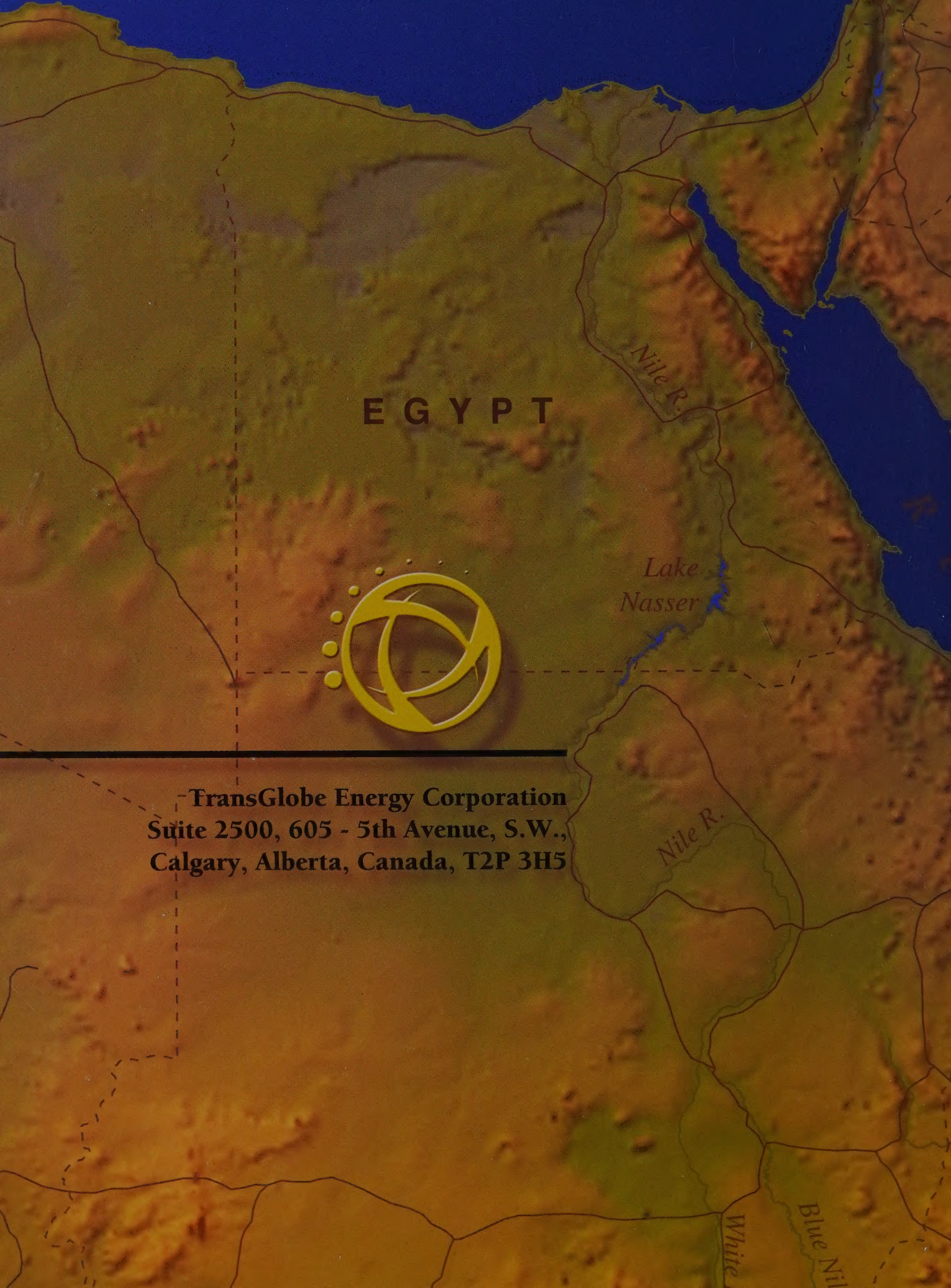
ABBREVIATIONS

C	Canadian
U.S.	United States
WTI	West Texas Intermediate
Bbl	barrel
Bopd	barrels of oil per day
Egypt	The Arab Republic of Egypt
Yemen	The Republic of Yemen
MBbls	thousand barrels
MMBbls	million barrels
Mcf	thousand cubic feet
Mcfpd	thousand cubic feet per day
MMcf	million cubic feet
MMcfpd	million cubic feet per day
GJ	gigajoule
Tcf	trillion cubic feet
Boe	*barrel of oil equivalent
Boepd	*barrel of oil equivalent per day
MBoe	*thousand barrels of oil equivalent
NGL	natural gas liquids
$MM	million dollars
the Company	TransGlobe Energy Corporation and/or its wholly owned subsidiaries
TransGlobe	TransGlobe Energy Corporation and/or its wholly owned subsidiaries
AMEX	American Stock Exchange
TSX	Toronto Stock Exchange
CPF	Central Production Facility
PSA	Production Sharing Agreement
MOM	Ministry of Oil and Minerals, Republic of Yemen
YOC	Yemen Oil Company
MD&A	Managements' Discussion and Analysis
GAAP	Generally Accepted Accounting Principles
G&A	General and Administrative
yr	year
Q	Quarter
○	drilling location
●	oil well
☼	gas well
⌖	abandoned well
⌀	injection well

* A Boe conversion ratio of 6 Mcf = 1 Bbl has been used. Boe's may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf to 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.



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